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MONITORING AND CONTROL REQUIREMENT DEFINITION STUDY FOR DISPERSED STORAGE AND GENERATION (DSG)

FINAL REPORT

Volume IV

October 1980

Prepared for

JET PROPULSION LABORATORY
CALIFORNIA INSTITUTE OF TECHNOLOGY

and

NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

Submitted by

GENERAL ELECTRIC COMPANY
CORPORATE RESEARCH AND DEVELOPMENT

GENERAL ELECTRIC

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MONITORING AND CONTROL REQUIREMENT DEFINITION STUDY FOR DISPERSED STORAGE AND GENERATION (DSG)

SRD-80-042-IV

FINAL REPORT

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Appendix C

IDENTIFICATION FROM UTILITY VISITS OF PRESENT AND FUTURE APPROACHES TO INTEGRATION OF DSG INTO DISTRIBUTION NETWORKS

Prepared for

JET PROPULSION LABORATORY
CALIFORNIA INSTITUTE OF TECHNOLOGY
(Contract No. 955456)

and

NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY
(Agreement No. ER 320-78/79 EUET)

Submitted by

GENERAL ELECTRIC COMPANY
CORPORATE RESEARCH AND DEVELOPMENT
Schenectady, New York 12301

GENERAL ELECTRIC

FOREWORD

This Final Report is the result of a year-long effort on Monitoring and Control Requirement Definition Study for Dispersed Storage and Generation (DSG) conducted by the General Electric Company, Corporate Research and Development, for the Jet Propulsion Laboratory, California Institute of Technology, and the New York State Energy Research and Development Authority.

Dispersed storage and generation (DSG) is the term that characterizes the present and future dispersed, relatively small (<30 MW) energy systems such as those represented by solar thermal electric, photovoltaic, wind, fuel cell, battery, hydro, and cogeneration. To maximize the effectiveness of alternative energy sources such as these in replacing petroleum fuels for generating electricity and to maintain continuous reliable electrical service to consumers, DSGs must be integrated and cooperatively operated within the existing utility systems. To effect this integration may require the installation of extensive new communications and control capabilities by the utilities. This study's objective is to define the monitoring and control requirements for the integration of DSGs into the utility systems.

This final report has been prepared as five separate volumes which cover the following topics:

VOLUME I - FINAL REPORT

Monitoring and Control Requirement

Definition Study for Dispersed Storage and Generation

VOLUME II - FINAL REPORT - Appendix A

Selected DSG Technologies and Their General Control Requirements

VOLUME III - FINAL REPORT - Appendix B

State of the Art, Trends, and Potential Growth of Selected DSG Technologies

VOLUME IV - FINAL REPORT - Appendix C

Identification from Utility Visits of Present and Future Approaches to Integration of DSG into Distribution Networks

VOLUME V - FINAL REPORT - Appendix D

Cost-Benefit Considerations for Providing Dispersed Storage and Generation of Electric Utilities

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ACKNOWLEDGMENTS

Throughout this study we have benefited greatly from the help offered by many people who are knowledgeable in specific areas of the dispersed storage and generation technologies studied and in the fields of communications, control, and monitoring. We particularly wish to acknowledge the efforts of and discussions with Dr. Khosrow Bahrami and Dr. Harold Kirkham, each of whom have served as technical manager in the Jet Propulsion Laboratory, and Dr. Fred Strnisa, project manager, New York State Energy Research and Development Authority.

We also wish to thank the various people with whom we met during our utility visits. The following utilities have provided useful information regarding DSG activities at their organizations:

Niagara Mohawk Power Corporation, Syracuse, New York

San Diego Gas and Electric Company, San Diego, California

Blue Ridge Electric Membership Corporation, Lenoir, North Carolina

Public Service Electric and Gas Company, Newark, New Jersey

In addition, we thank our many associates in General Electric Company who have helped so much in our understanding of the selected DSG technologies and in the integration of DSGs into the existing electric utility system. In particular, we thank J.B. Bunch, A.C.M. Chen, M.H. Dunlap, R. Dunki-Jacobs, W.R. Nial, R.D. Rustay, and D.J. Ward.

The help of Dr. Roosevelt A. Fernandes of Niagara Mohawk Power Corporation in several phases of the work covered in this report is acknowledged with thanks. Also, Dr. Fred C. Schweppe, consultant, has been of considerable benefit in the conduct of this project and his efforts have been appreciated.

Harold Chestnut

Robert L. Linden

ABSTRACT

A major aim of the U.S. National Energy Policy, as well as that of the New York State Energy Research and Development Authority, is to conserve energy and to shift from oil to more abundant domestic fuels and renewable energy sources. Dispersed Storage and Generation (DSG) is the term that characterizes the present and future dispersed, relatively small (<30 MW) energy systems, such as solar thermal electric, photovoltaic, wind, fuel cell, storage battery, hydro, and cogeneration, which can help achieve these national energy goals and can be dispersed throughout the distribution portion of an electric utility system.

As a result of visits to four utilities concerned with the use of DSG power sources on their distribution networks, some useful impressions of present and future approaches to the integration of DSGs into electrical distribution network have been obtained. A more extensive communications and control network will be developed by utilities for control of such sources for future use.

Different approaches to future utility systems with DSG are beginning to take shape. The new DSG sources will be in decentralized locations with some measure of centralized control. The utilities have yet to establish firmly the communication and control means or their organization. For the present, the means for integrating the DSGs and their associated monitoring and control equipment into a unified system have not been decided.

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Section C1

INTRODUCTION

As a result of short, one day visits to four utilities concerned with the use of dispersed storage and generation (DSG) power sources on their distribution networks, some useful impressions of the present and future approaches to the integration of DSG technologies into electrical distribution networks have been obtained. The utilities visited included:

- Niagara Mohawk Power Corporation (NMPC) - Syracuse, New York
- San Diego Gas and Electric Company (SDG&E) - San Diego, California
- Blue Ridge Electric Membership Corporation (BREMCO) - Lenoir, North Carolina
- Public Service Electric and Gas Company (PSE&G) - Newark, New Jersey

The primary objectives of these visits were to identify the utilities opinions on the following key issues:

- Utility criteria for judging the suitability of DSG for incorporation into distribution networks
- Influence of DSGs on present utility practices and hardware
- Utility plans for distribution automation and control (DAC) and its integration with DSG

Present approaches seem to consist in large part of an extension of past practices with such DSGs as hydro and cogeneration where there currently exist such sources of DSG power. A more extensive communication and control network will be developed for control of such sources, and more continuous monitoring and automatic remote control means will be available for future use. Extensions of present power scheduling methods are being used to incorporate the effects of additional generation capacity provided by DSG.

New DSG means to provide new sources of power are being developed for future installation. The new DSG means will be in decentralized locations with centralized control. Future utility systems with DSG are beginning to take shape. The utilities have yet to establish firmly the communication and control means or their organization. For the present, the means for integrating the DSGs and their associated monitoring and control equipment into a unified system have not been decided.

Section C2

SUMMARY OF IMPRESSIONS

As a result of the utility visits and other ideas gained from a previous review of the DSG technologies, certain impressions were formed.

C2.1 High Utility Interest in DSG

The utilities visited seemed genuinely interested in having more dispersed storage and generation power sources available to meet increasing generation needs. Many utilities face increasing customer loads and feel they need more generation equipment located near distribution substations and capable of using renewable energy sources or more economical means of generating power. For a number of reasons, however, progress seems slow in bringing the actual dispersed storage and generation into being. In some cases DSG costs are not competitive with conventional generation means or "free" energy sources are not available in sufficient quantity to be practical. In still other cases, it has been difficult to obtain all the approvals required.

C2.2 Purchase of Customer Surplus Power

A few utilities are formulating policies that would enable willing customers to generate power which could be fed into the utility lines. Some utilities refer to this practice as "cogeneration." Although the utilities appear more receptive than in past years to purchasing such electricity from customers, it is not clear that the average price the utilities are willing to pay for "cogenerated" power will be sufficiently high to make such an arrangement attractive to owners of the cogeneration facility.

In addition to establishing a rate structure for purchasing customer-generated power, the utilities are working out "design operating guides" to maintain jurisdiction of the power interface and protection between the DSG and the distribution power network. Concern with "backfeed" has been expressed to insure that operator safety is maintained when parallel generation by customer and utility is employed.

C2.3 Improving Monitoring and Control

The advent of microprocessors and improved communication means has provided the utilities with an increased opportunity to directly control and monitor remote DSGs. Whereas telephone lines and voice communication have in the past provided information to and from remote DSG energy sources, more frequent and flexible data transfer from DSGs to the distribution dispatch center (DDC) will be desired and used in the future.

C2.4 Scheduling of DSGs

Representatives of some of the utilities' planners and operating personnel expressed the idea that energy scheduling of DSGs may not turn out to be a major technical problem when the DSG power supplied amounts to less than 10% of the total power dispatched. Although the figure 10% appears merely to be a "rule of thumb," the present use of remote hydro and cogeneration in a de facto DSG mode, without any appreciable operating problems, indicates that future scheduling difficulties of DSGs may not be very severe.

The presence of many small DSGs introduces some diversity, which increases the likelihood of available generation when needed, despite the inherent uncertain availability of power from some DSGs at any particular time. Further, with increased operating experience, it should be possible to develop some correlation among past generation patterns and current estimates.

When DSGs are more commonly accepted, new scheduling logic will no doubt be required. It would appear that work could begin soon on consideration of a basic approach to scheduling of generation by various DSGs.

Section C3

BRIEF DESCRIPTION OF UTILITY VISITS

The following is a brief description of the visits made to the four utilities involved. Emphasis is on the present characteristics of the utilities, the attitude of each toward the subject of DSG in specific technologies, and plans for integrating DSG into their distribution network.

C3.1 Niagara Mohawk Power Corporation — Syracuse, New York

Attendees (July 31, 1979)
NMPC
Hilary Nortz, Chief Power Dispatcher
Roosevelt Fernandes, R&D

GE
J.B. Bunch, Corporate Research and Development (CRD)
Harold Chestnut, CRD

Attendees (August 24, 1979)
NMPC
Charles Fuller, Hydro Operations and Maintenance
Jack LaClair, Hydro Projects and Automation
Dave Birlbeck, Hydro Planning
Roosevelt Fernandes, R&D

GE
Robert Linden, Projects Engineering Operation (PEO)
Harold Chestnut, CRD

Note on Table C3.1-1 a number of pertinent statistics for the Niagara Mohawk Power Corporation customers, loads, and other characteristics. In addition to generating nuclear, oil, and coal power, NMPC uses hydro generation and purchased electric power to meet its system needs.

Niagara Mohawk has for many decades used hydro power as a valuable source of energy. Presently they have approximately 80 small hydro plants totaling 666 MW. By 1990 they plan to have 16 new hydro generating units with almost 200 MW of added capacity. Table C3.1-2 is a summary of the new hydro generation planned. With the exception of the two Hudson Falls plants, the remaining plants will not require new dams. Many of these new units can be considered as dispersed sources of generation.

Niagara Mohawk also has an interest in other sources of dispersed storage and generation. In particular, NMPC has been considering fuel cells and storage batteries as possible additions to its network. For the present NMPC does not feel that solar thermal electric, photovoltaic, or wind sources of energy will be of early benefit to them.

Table C3.1-1

NIAGARA MOHAWK POWER CORP. STATISTICS*

Combination Co Elec & Gas
Elec Cust Res 1, 180, 316 Com 126,678 Indl 2,835 Others 2,256
Total 1,312,085
Gas Cust 413,065
Elec Res Cust Avg Rate 3.82¢/kWHR, Use 6,599 kWHR
Tot No/Employees (Full Time, Year End) 9,238
Approx. 65% Electric Employee
Approx. 20% Gas Employees
Approx. 15% General Employees

MAJOR INTERCONNECTIONS at 69, 115, 230, 345 kV

1977 Tot Sys Input 33,408,649,000 kWHR
1977 Energy Pur 11,463,723,914 kWHR
1977 Sales for Resale 2,107,307,000 kWHR
1977 Sales to Ultimate Consumers 28,417,022,000 kWHR
1977 System Generation 21,944,925,300 kWHR
1977 Total Sales/Electric 30,524,329,000 kWHR
No/Bulk Power Substa 214, Tot kVA 15,345,609
No/Distr Substa 731, Tot kVA 6,233,055

Transm Volt 12, 13.2, 23, 34.5, 38, 46, 69, 115, 230, 345 kV
Cir Miles 9,061
Distr-Prim Volt 2.4, 4.16, 4.8, 13.2 kV Wire Miles 105,908
Underground Cable Miles Transm 910, Prim Distr & Secondary 5,651

System Thermal Capacity 4,220,566 kW
System Hydro Capacity 665,740 kW

Tot Gen Cap as of Jan 1, 1978 4,886,306 kW
Sys Peak (Summer) 4,878,000 kW, (Winter) 5,284,000 kW

*Source: 1978-79 Electrical World's Directory of Utilities

C3.2 San Diego Gas and Electric Company — San Diego, California

Attendees (September 20, 1979)

SDGE
James Hunter, Marketing
Robert Eckley, Generation Engineering
Raymond Vick, Marketing
David Hopkins, Distribution Engineering Manager

Applied Energy, Inc.
Paul Hodiak, Manager
Charles Harmstead, Engineer

GE
George Barcus, Electric Utility Sales, San Diego
A.C.M. Chen, CRD
Harold Chestnut, CRD

Table C3.1-2

NEW NIAGARA MOHAWK HYDRO PLANT FACILITIES PLANNED* FOR 1980-1990

Location	Rating (MW)
Sugar Island	2.4
Oswegatchie	1.4
Felts Mill	11
Glen Park	20
Gramby	10
Trenton	9
Dolgeville	2.6
Spier	25
Fort Edward	10
Hudson Falls (2)	60
South Glens Falls	10
Feeder Dam	2
Sherman	8
Hadley	25
Union	2.4
Total	198.8

*NMPC plans to install approximately 15 new (1- to 60-MW) hydrogeneration facilities by 1990. Their present 80 small hydro plants total 660 MW.
Source: Niagara Mohawk Power Corporation

San Diego Gas and Electric has been interested in cogeneration since 1968 and supplying both steam and electricity to a few customers, primarily the U.S. Navy, since 1972. SDG&E has a wholly-owned subsidiary, Applied Energy, Incorporated (AEI), which operates three SDG&E cogeneration facilities at naval military installations in the San Diego area. A civilian cogeneration facility was placed in service in 1979 at the Chula Vista plant of Rohr Industries. Rohr uses the steam for its industrial processes, and SDG&E can use any surplus electricity.

Table C3.2-1 contains pertinent statistics for the San Diego Gas and Electric's customers, load, and other characteristics.

Table C3.2-1

SAN DIEGO GAS AND ELECTRIC CO. STATISTICS*

Combination Co. Elec & Gas
Elec Cust: Res 613,886 Com 51,050 Power 7,171 Other 829
Total 682,946
Gas Cust 461,956
Elec Res Cust Avg Rate 4.45¢/kWHR, Use 5,756 kWHR
Elec Dept Employees (Full Time, Year End) 2,946
Tot No/Employees (Full Time, Year End) 4,040

MAJOR INTERCONNECTIONS at 230 kV

1977 Net Sys Input 9,390,967,632 kWHR
1977 Power Purchased 795,221,700 kWHR
1977 Power Port, Gas Turbine 74,810 kWHR
1977 Sales/Elec 8,676,313,018 kWHR
No/Bulk Power Substa 5, Gen Step-up Substa 1,789,400 kVA
Transm 11/Transm 3,228,[illegible]00 kVA
Transm 61 Distr Substa 2,931,900 kVA
Transm Volt 230 kV, Pole Miles 89.65

Transm Volt 138 kV, Pole Miles 248.6
Transm Volt 69 kV, Pole Miles 704.26
Distr-Prim Volt 2.4 - 4.16 - 12.0 kV, Pole Miles 7,006.16

Tot Gen Cap as of Jan 1, 1978 2,105,000 kW
Sys Peak (Summer) 1,746,000 kW, (Winter 1,667,000 kW

*Source: 1978-79 Electrical World's Directory of Utilities

Since SDG&E has good prospects for adding system load in the years to come, but limited prospects for additional central generation, SDG&E has a definite interest in exploring new ways of obtaining additional energy. Although solar thermal electric might appear an attractive candidate as an additional energy source, it was not apparent that SDG&E people felt this sort of solar energy could be made economically attractive for the present. Solar energy for providing hot water at customer locations has received considerable attention by SDG&E as a customer service.

San Diego Gas and Electric Co. has under development a company policy related to cogeneration which will establish rates and schedules for customers wanting to sell energy, primarily electrical, to the utility from customer-owned generation sources. The general tenor of this policy is to "encourage" customer generation from dispersed sources and to pay for this power at a mutually agreed upon rate related to the utility's generation cost and in accordance with applicable government regulations. To insure proper interconnection and protection of SDG&E distribution equipment

when a customer-owned power source is connected to a SDG&E feeder, SDG&E will perform the equipment interconnection in accord with a yet-to-be-agreed-upon company policy as set forth in a preliminary fashion in Appendix CIV.

C3.3 Blue Ridge Electric Membership Corporation — Lenoir, North Carolina

Attendees (September 24-25, 1979)
BREMCO
G.R. Ayers, Director of Engineering

GE
J. Brown, Valley Forge
D.J. Ward, Power Distribution Systems Engineering (PDSEO)
H. Chestnut, CRD

Blue Ridge Electric Membership Corporation is an electric utility which presently purchases most of its electric power from the Duke Power Company at an average rate per kilowatt hour related to Duke Power's annual average generation cost. Table C3.3-1 presents a summary of a number of pertinent statistics regarding BREMCO's customers, loads, and equipment size.

Table C3.3-1

BLUE RIDGE ELECTRIC MEMBERSHIP CORP. STATISTICS*

Elec Cust: Res 30,278 Com 1,766 Indl 195 Others 2,335 Total 34,574
Elec Res Cust Avg Rate 3.63¢/kWHR, Use 8,751 kWHR
1977 Power Purchased 589,191,998 kWHR
1977 Sales/Elec 536,976,940 kWHR
Transm Volt 44 kV & 100 kV, Cir Miles 255
Distr-Prim Volt 7.6/13.2 kV, Pole Miles 4,565
Sys Peak (Summer) 85,972 kW (Winter) 134,592 kW
Tot Sys Incoming Substa Cap (nameplate-maximum) 150,000 kVA
Power Purchased From: Duke Power Co. & SEPA

*Source: 1978-79 Electrical World's Directory of Utilities

The U.S. Department of Energy (DOE) has chosen Howard's Knob overlooking Boone, N.C. as the site for the world's largest wind generator. The 2000-kW wind turbine generator (WTG) is used in a research project to determine if wind can be used effectively to generate electricity. Blue Ridge Electric Membership Corporation will operate the wind generator, which the General Electric Company is installing, and the electricity generated will be fed into the Blue Ridge Electric distribution system. The National Aeronautics and Space Administration (NASA) manages the project. Blue Ridge Electric was selected for its role in 1977.

The wind generator has local computer control. A remote terminal at the Lenoir dispatch office (some 26 miles away) permits BREMCO to monitor the status of the unit and supervise the automatic control. For example, the wind conditions and machine output can be obtained from this telephone-linked terminal. In addition, the operator can enable or disable the unit from operating under automatic control. Similar capability exists at the control house in Boone, N.C. where the WTG is situated.

C3.4 Public Service Electric and Gas Company — Newark, New Jersey

Attendees (September 28, 1979)
PSE&G
Murty Bhavaraju, System Planning
Brian Daly, System Planning
Andrew Johnson, System Planning
Wei Shing Ku, System Planning
Stephen Mallard, V.P. System Planning
T.M. Piascik, Systems Planning
Bill Wood, Systems Planning

GE
Jennings Bunch, CRD
Harold Chestnut, CRD
Max C. Schramm, Florham Park

Public Service Electric and Gas has for at least five years actively studied the possible use of dispersed storage and generation both in general and in particular for its own use. Table C3.4-1 presents the pertinent statistics for PSE&G concerning number of customers, electrical loads, total generation capacity, and other summary data.

Public Service Electric and Gas believes that storage batteries and fuel cells have the greatest potential for application on its system. However, there also has been an effort to identify the amount of wind, water, and solar energy available for use in the geographical areas of interest to PSE&G. Public Service Electric and Gas is offering assistance to its customers in solar water heating equipment and installation.

A major effort by PSE&G has been underway on a Battery Energy Storage Test (BEST) facility for studying the characteristics and operational experience of using electric batteries at the distribution substation level in an electric utility system. To date the emphasis has been on the design and construction of the BEST facility. A rather complete plan for instrumentation and testing has been prepared and is in the process of implementation to facilitate the test program.

Another area of PSE&G activity has been the economic assessment of the utilization of DSGs in electric utilities. Particular attention has been given to examining the PSE&G system with respect to installation of batteries which could defer or cancel costly transmission projects.

Table C3.4-1

PUBLIC SERVICE ELECTRIC AND GAS CO. STATISTICS*

Comb Co. Elec & Gas
Elec Cust: Res 1,464,331 Com 184,811 Indl 7,948 Others 4,513
Total 1,661,603
Gas Cust 1,307,320
Elec Res Cust Avg Rate 6.34¢/kWHR, Use 5,403 kWHR
Elec Dept Employees (Full Time, Year End) 9,018
Tot No/Employees (Full Time, Year End) 13,339

MAJOR INTERCONNECTIONS [illegible] .38, 230, 345 & 500 kV

1977 Net Sys Input 25,[illegible]23,000 kWHR
1977 Power Purchased & Interchanged 5,269,587,000 kWHR
1977 Sales/Elec 28,442,879,167 kWHR
No/Bulk Power Substa 37, Tot kVA 25,157,200
No/Distr Substa 252m Tot kVA 6,248,250

Transm Volt 69, 138, 230 & 500 kV, Cir Miles 1,031
Transm Volt 26.4 - 33 kV, Cir Miles 1,448
U.G. Conductor Miles: Transm 2,424, Distr 15,678

Tot Gen Cap as of Jan 1, 1978 10,235,318 kW (NP)
Sys Peak (Summer) 6,895,000 kW, (Winter) 4,839,000 kW

*Source: 1978-1979 Electrical World's Directory of Utilities

Section C4

UTILITY VIEWPOINTS ON KEY ISSUES

C4.1 Utility Criteria for Judging Suitability of DSG

The primary criterion the utilities use for judging the suitability of a DSG technology application is economic. Although for research and development purposes attention may be given to a DSG technology that may not presently be economically viable, there is the tacit understanding that in the long run there is promise of an economic benefit to the utility from the use of the DSG technology being considered.

Niagara Mohawk Power Corporation considered a benefit cost analysis to be the basis for justification. Total cost includes land, construction, installation, capital equipment, financing, taxes, energy needs, operation and maintenance, etc. Annual costs are built upon an annual fixed charge rate of about 20% of total initial costs including installation. In addition the operating and maintenance costs are determined on an annual basis.

The NMPC benefits of dispersed hydro generation include improved heat rates of central thermal generation units not undergoing changing loads, improved hydro turbine efficiency by control of blade angle over existing non-controllable blade angle hydro units, and improved area regulation through reduced cost of purchased power and improved selling of available power. Before considering any DSG for investment planning purposes, it is necessary that the technology be "proven" and commercially available.

At San Diego Gas and Electric economics appears to be the paramount utility criterion for judging the suitability of DSGs. There is no specific "energy-saved" evaluation made although the efficiency of operation is included in the calculation process. SDG&E has established a wholly-owned subsidiary, Applied Energy, Incorporated, which operates cogeneration facilities and is presumably able to sell electricity and process steam to customers on a somewhat different economic basis than if SDG&E were to deal directly with the customer.

Another factor which appears to be of considerable importance to SDG&E in connection with DSG is the matter of safety. This issue has been identified with the problem of "backfeed," whereby a feeder that has been removed from the substation bus and presumably has been deenergized, may in fact still be energized from the DSG source located elsewhere on the same feeder. Provisions are made in the agreement with the customer, in the case of any customer-supplied generation, for the utility to be able to disconnect the customer from the utility line if it becomes necessary to deenergize the utility line for maintenance or service.

Economic factors are the prime consideration by the Blue Ridge Electric Membership Corporation in justifying DSG. BREMCO visualizes energy savings as important only as they relate to economics. Note that the BREMCO 2-MW wind turbine generator was originally funded through ERDA and is now part of the Department of Energy's program funding. DOE and BREMCO are still evaluating the feasibility, availability, and reliability of the wind turbine generator unit.

At Public Service Electric and Gas the system planners believe, based on economic considerations, that storage batteries and fuel cells have the greatest potential for application to their utility system. Investment savings represent an attractive economic benefit.

Although fuel cells may represent an efficient use of energy, storage batteries do not represent a source of "free" energy. The absence of any highly attractive energy sources from wind, water, or sunshine in the New Jersey locale of PSE&G, means that DSGs dependent on such energy sources are not likely to be economically desirable to PSE&G.

As noted, the utilities visited have not found energy savings per se to represent a significant criterion for judging a DSG. Perhaps in the future there will be federal regulations or tax benefits which will allow a credit for renewable energy used to generate electrical power. For the present such benefits do not generally exist. More conventional economic analyses are used to evaluate whether or not DSG energy sources can be justified.

Other factors such as availability, reliability, and other operational considerations enter into the economic evaluation of a DSG power source. Since the natural uncertainties of such energy sources as wind, sun, and water are sufficiently high, the unavailability or the unreliability of the generation equipment and its control are likely to be considerably less than the uncertainty of the natural phenomena involved. This natural uncertainty must be taken into account in rating a DSG in terms of its capacity factor, i.e., the per unit portion of the nameplate rating of the DSG that can be considered credited as "firm" generating capacity for the system.

C4.2 Influence of DSG on Present Utility Practices and Hardware

The advent of more extensive use of DSG will bring about an increased emphasis on communication needs from a distribution dispatch center (DDC) to the DSG sites. Presently, there tends to be relatively little realtime, continuous communication from a distribution center to remote distribution substations. However, communication of this sort will be required in the future.

At present, the utilities tend to use telephone lines for such communication purposes when the local telephone service is adequate. However, several of the utilities visited have undertaken

studies to determine, in terms of performance and cost, the most effective communication means. Much remains to be done before a well-established set of communication equipments and procedures is in place.

NMPC currently has a communication study under way to establish its future communication plans. As new hydro units are installed, means for remote automatic control interfaces are planned for inclusion, even though such equipment may not be used initially when the hydro unit is first placed in service.

In the case of SDG&E, each of the cogeneration DSGs has been handled through Applied Energy, Incorporated, a wholly-owned subsidiary. Any changes needed are handled by transferring them to AEI for initiation and implementation. So far, according to SDG&E Distribution Engineering personnel, cogeneration appears to have minimal impact on implementation.

Presently, SDG&E remotely controls the AEI-operated machines, via telephone to a local on-site operator. In the future SDG&E envisages microwave links in addition to the telephone connection. AEI presently has all four sites staffed 24 hours a day. For units greater than seven or eight megawatts, staff will probably be pres- at all times. Smaller rated sites, those as low as 0.8 MW, might be unmanned. The gas turbines presently used are started locally not remotely. For the immediate future SDG&E visualizes that the remote dispatcher will be able to monitor only whether or not the cogeneration unit is operating. The dispatcher could not start the unit remotely.

BREMCO plans to have a remote terminal available at its central dispatching facility at Lenoir, N.C. A telephone will couple the terminal to the wind turbine generator at Howard's Knob, Boone, N.C. In addition, a minor change in protection practice will be the blocking of automatic reclosing at the substation for the feeder tied to the wind turbine generator.

PSE&G is concerned with possible backfeed on radial feeders with DSG sources located out on the feeders away from the distribution substation where the feeders have traditionally been energized.

The availability of additional DSG storage and generation capacity will provide additional resources to central power dispatchers who will allocate power as they perform their daily and periodic load scheduling. Although the particular availability characteristics associated with each specific DSG source must be included in the logic procedure, the basic approach appears to be a logical extension of scheduling methods currently in use. As long as the added power supplied by DSG amounts to 10% or less of the peak power, there should be no major changes in scheduling methods. However, in the event that the DSG generation becomes a much larger percent of the peak load, it may be necessary to revise the scheduling procedure to include the effect of uncertainties in the dispersed storage and generation power sources.

C4.3 Distribution Automation and Control

The subject of distribution automation and control is one of considerable interest to the three largest of the four utilities visited. Each has one or more research and development programs underway to study what might be done for their utility through the use of DAC. However, it is by no means evident at this time which courses of action each utility will ultimately take on the subject of DAC.

Niagara Mohawk and Public Service Electric and Gas have participated in the General Electric PROBE project for several years now, and each of these utilities has done its own internal work, as well as contracted with other manufacturers in the DAC field.

To date SDG&E has not found its studies on DAC very encouraging. However, those function directed toward improving reliability have been considered most favorably. The effort here is to convert radial feeder arrangements into loop structures.

Lately, the real change in distribution at SDG&E has been the trend to underground distribution associated with aesthetic reasons and fostered by new residential construction. California utilities have been encouraged by law to allocate a certain small percentage of revenue to defray the cost of underground distribution. In the long run this kind of distribution may require more DAC than was previously the case. For the present at SDG&E, there appears to have been little coupling of DSG into the DAC thinking of planning or operations people.

Section C5

IMPORTANT ITEMS IDENTIFIED

During the course of the utility visits a number of items were discussed that have a high degree of importance and detail pertinent to future work in the monitoring and control of DSGs. These items are described briefly below and presented in more detail as part of the appendices to this report.

C5.1 System Daily Power Log

Dispersed storage and generation represents an element of power contribution to the overall system power of a utility. Currently each utility prepares in advance a system power log on an hour-by-hour basis for each of its generation sources. When DSG sources are installed in a system, it is necessary to schedule them as part of the power-time requirements used as a basis for monitoring and control.

Appendix CI shows a NMPC System Generation, Tieline, and Load Summary for the 24-hr period of 6/15/79. A number of hydro plants, similar to those being considered under DSG hydro technology, are indicated. Presumably, with DSG present, items would have to be included for the contribution of the various DSG sources. Methods for integrating the generation from other sources with that of the DSG sources are required as a result of the incorporation of DSG with the existing power generation means.

C5.2 AUTOMATIC LOAD CONTROL (ALC)

In addition to the scheduling of DSG power, as described in Section C5.1, there exists a control problem of establishing the desired amount of load which should be assigned to each of the several DSGs at any particular time. NMPC has a Raquette River Development that consists of five hydroelectric plants tied together through their location on the same river.

The material in Appendix CII describes the reasoning used to decide in what order the various hydro generators should be started up, loaded, and shut down. Descriptive logic, such as presented here, will be the initial basis for the development of the control logic done either by the automatic generation control (AGC) of the load or by remote scheduling to each of the generation sources on SCADA-type communication links. For automatic generation control of several DSG technologies and multiple units it will be necessary to develop a control philosophy from load control information such as that described in Appendix CII.

C5.3 SDGE — General Service Contract Including Customer Generation

Cogeneration is one DSG technology which holds considerable promise for early and financially attractive utilization. Appendix CIII presents a preliminary version of a necessary agreement, the General Service Contract, between utility and customer so that each will benefit economically from cogeneration and so that each will have available the terms and conditions for doing business.

Since the time of these visits, the Federal Energy Regulatory Commission (FERC) has issued 18CFR Part 292 - Regulations Under Section 201 and 210 of the Public Utilities Regulatory Policy Act of 1978 (PURPA) with Regard to Small Power Production and Cogeneration (45FR 12233, February 25, 1980). The rules require electric utilities to purchase electric power from and sell electric power to qualifying cogeneration and small power production facilities, and to provide for the exemption of qualifying facilities from certain federal and state regulation. Implementation of these rules is reserved to State regulatory authorities and nonregulated electric utilities.

C5.4 DSG Design and Operating Guides for Safe Integration of Customer's Generation into the Utility's Distribution System

In order to integrate a customer's generation facility into the utility's distribution system, it is desirable to establish in advance the design and operating guides. San Diego Gas and Electric Company has developed a preliminary version of such guides (Appendix CIV).

C5.5 One-Line Diagram of Wind Turbine Generator at BREMCO

In the case of the wind turbine generator at Boone, N.C., which BREMCO will operate, the DSG will be under the control of the utility rather than a customer. Appendix V shows a one-line diagram of the way the wind turbine generator connects to the BREMCO feeder.

During abnormal conditions the wind unit can be shut down remotely via computer control or locally via an operator. The only change in protection practice is the blocking of automatic reclosing at the substation for this feeder. The BREMCO operator at Lenoir must also concur before reclosing at the substation can take place.

C5.6 Average Windspeed Data at Boone, NC

Appendix CVI shows the monthly variation in the average wind speed at Boone, North Carolina. The data serve to illustrate that the wind is available predominantly in the winter, while the summer months may barely have enough wind to generate electricity since 11 mph is the cut-in speed.

C5.7 Representative Data to Be Transmitted from Remote DSG to DDC Monitoring Site

It is recognized that differing DSG technologies and differing DSG means within a particular technology will probably require monitoring and controlling different data. Nevertheless, it is worthwhile to consider what might be representative of the data that might be transmitted from a remote DSG to the corresponding DDC monitoring site. Appendix CVII shows such a list of representative data for the BREMCO wind turbine generator at Boone, North Carolina.

From consideration of these data, it would appear that approximately 100 data items can be used to describe the significant characteristics or operating conditions for a representative wind generator. The figure of 100 data items will doubtlessly be more than required for some small DSGs, while more information may be required for larger DSGs under certain circumstances. From the data shown, it can be seen that about an equal amount of data appears to be of an on-off character as of a quantitative nature. More DSG applications should be considered before drawing any meaningful kind of inferences.

C5.8 Economic Assessment of Specific DSGs

The importance of economic evaluations as a basis for deciding whether or not to justify the use of one or another DSG was emphasized by the representatives of the utilities during these visits. Appendix CVIII is an executive summary of an example of an economic assessment.

Section C6

CONCLUSIONS AND OBSERVATIONS

As a result of visits to four utilities, the following conclusions and observations were formed:

- The subject of dispersed storage and generation of electrical energy is of considerable interest to electric utilities. Some utilities are actively engaged in research, development, and planning activities on DSG, and they are willing to cooperate with others on DSG projects. However, the use of DSG in utilities is not very advanced and continued study of DSG is required.
- The criterion used by the utilities for deciding whether or not to install DSG is primarily economic, with safety considerations also of concern. Although the utilities recognize the saving of imported petroleum as a matter of importance, the economic evaluation procedures do not appear to contain specific incentives for decreasing the amount of imported petroleum per se. Ways of providing inducements to reduce petroleum imports should be developed through U.S. Government incentives so that reducing petroleum imports becomes more attractive to the utilities.
- Utilities see a need for improved remote monitoring and control of DSGs and favor going to more automatic, remote control means. Although manual control of remote generating stations in larger sizes (> 10 MW) is currently employed, the future goal is unmanned operation. Work on more complete communication to remote DSG sites is of interest to at least two of the four utilities involved in these visits. The possibility of a demonstration project for DSG remote monitoring and control should be explored.
- Although in the long run the influence of DSG on electric utility generation scheduling and control will probably be fairly significant, for the present the effect of DSGs on power scheduling appears small and slowly changing. DSG scheduling does not appear to be a major problem; and the presence of DSGs appears to be an asset. However, consideration of developing improved means for the scheduling of DSGs should start soon.
- DSG and distribution automation and control are presently considered as somewhat separate activities, with DSG being considered as part of generation (energy system management). DAC, considered part of distribution, has not developed a strong enough economic justification at the present time. Therefore, DSG cannot count on DAC to provide the basic communication network needed for DSG.

- Greatly increased expansion of installed DSG will be aided by the availability of lower cost fuel cells and storage batteries. It appears that 5 to 10 years will elapse before the appropriate storage and generation sources will be available at sufficiently attractive prices for introduction of extensive DSG capacity, i.e., >10% of the installed system generation.
- Utilities are preparing cogeneration policies for purchasing customer surplus power and for providing suitable design and operating guides for DSG usage in distribution networks. More work on policy development is needed to encourage utility and customer awareness and familiarity with DSG cogeneration possibilities.

Appendix CI

NIAGARA MOHAWK POWER CORPORATION
SYSTEM POWER LOG FOR FRIDAY 6/15/79

To provide an indication of the dimensions of the problem in scheduling various dispersed storage or generation power equipments, reference should be made to the NMPC System Generation, Tieline and Load Summary (Tables CI-1 to CI-9) received from R.A. Fernandes of NMPC for the 24-hr period of 6/15/79. Each page of the log is for a 12-hr period. The log is for a total of approximately 150 different units. The last few pages are a summary of the power exchange and are more or less a record of what took place during the time period.

Table CI-1

NMPC SYSTEM GENERATION, TIELINE AND LOAD SUMMARY
FOR 6/15/79 24-HR PERIOD

LOGP01 SYSTEM POWER LOG FOR 166 FRI 06/15 TODAY 15 169 MON 6/18/79 TIME 8 38

LINE	01	02	03		05	06	07	08	09	10	11	12	TOTAL
1													
2 SALMON HYDRO	0	0	0	0	0	0	0	19	18	31	31	31	285
3 OSWEGO HYDRO	13	13	13	13	13	13	13	14	14	11	11	11	306
4 UTICA HYDRO	2	2	2	2	3	3	7	11	25	25	25	25	381
5 WATERTOWN HYDRO	31	31	31	31	31	31	30	31	38	47	44	46	860
6 COLTON HYDRO	58	70	69	66	76	75	74	111	136	159	163	172	2787
7 ALBANY HYDRO	58	48	48	43	43	52	43	127	124	141	171	163	2523
8 MEDINA & LOCKPORT HYDRO	5	5	5	5	6	6	6	6	6	6	6	6	132
9 NM TOTAL HYDRO	167	169	168	160	172	180	193	319	373	420	451	452	7256
10													
11 DUNKIRK STEAM	450	419	369	390	366	408	453	466	461	460	462	464	10418
12 HUNTLEY STEAM	391	318	306	251	250	254	362	461	491	489	486	483	10353
13 OSWEGO STEAM	679	516	513	512	513	513	501	740	1022	1074	1089	1066	20667
14 NINE MILE NUCLEAR													0
15 NINE MILE DIESEL													0
16 ALBANY STEAM	190	183	183	183	180	182	188	274	320	305	359	361	7176
17 ALBANY GAS TURBINES	0	0	0	0	0	0	0	0	0	0	0	0	0
18 ROTTERDAM GAS TURBINES	0	0	0	0	0	0	0	0	0	0	1	67	525
19 ROSETON STEAM (NM SHARE)	90	90	90	90	90	90	91	158	175	176	176	176	3536
20 NM TOTAL THERMAL	1600	1426	1361	1326	1299	1347	1595	2099	2469	2504	2573	2615	52815
21													
22 RANKINE HYDRO	28	27	29	28	27	27	27	27	29	29	29	29	726
23 BUFFALO COLOR (+)	0	0	0	0	0	0	0	0	0	0	0	0	0
24 KENTS FALLS HYDRO	21	18	18	15	15	15	18	18	18	16	16	17	408
25 CEDARS DELIVERED (N-S+)	79	80	81	79	81	79	80	77	80	77	79	79	1892
26													
27 PASNY NIAGARA (TO NM +)	1390	1256	1090	1061	1041	1059	1546	1701	2115	2296	2293	2238	44036
28 PASNY FITZPATRICK								0	0	0	0	0	0
29 PASNY GILBOA (GEN+ PUMP-)	-281	-277	-277	-277	-275	-274	0	0	250	475	677	676	3743
30 PASNY ST LAWRENCE (TO NM +)	857	861	856	860	858	857	866	862	859	849	853	850	20667
31 PASNY TOTAL QUEBEC (TO NM +)	1127	1128	1129	1128	1129	1130	1128	1131	1132	1132	1132	1133	27088
32													
33 CONTROL AREA TOTAL GENERATION	4898	4598	4365	4290	4257	4330	5360	6076	7150	7622	7927	7921	155151
34													
35													

Table CI-2

NMPC SYSTEM GENERATION, TIELINE AND LOAD SUMMARY FOR 6/15/79 24-HR PERIOD

LINE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]				
1													
2 SALMON HYDRO	31	31	31	31	31	0	0	0	0	0	0	0	285
3 OSWEGO HYDRO	12	13	12	13	13	13	13	13	13	13	13	13	306
4 UTICA HYDRO	30	30	31	30	30	30	30	30	2	2	2	2	381
5 WATERTOWN HYDRO	41	42	40	45	41	46	29	32	27	26	25	26	840
6 COLTON HYDRO	163	154	155	164	106	94	113	110	139	166	83	101	2787
7 ALBANY HYDRO	142	130	130	105	125	129	84	131	138	139	130	57	2523
8 MEDINA & LOCKPORT HYDRO	5	5	5	5	6	6	6	6	5	5	5	5	132
9 NM TOTAL HYDRO	424	405	406	393	352	318	275	322	324	351	258	206	7254
10													
11 DUNKIRK STEAM	463	465	467	434	433	436	453	457	461	459	462	460	10618
12 HUNTLEY STEAM	483	482	483	483	483	488	486	496	499	493	491	444	10353
13 OSWEGO STEAM	1099	1089	1067	1069	1067	1076	1053	1041	1031	1071	1044	924	20667
14 NINE MILE NUCLEAR													0
15 NINE MILE DIESEL													0
16 ALBANY STEAM	355	365	367	362	362	361	341	360	359	361	359	294	7174
17 ALBANY GAS TURBINES	0	0	0	0	0	0	0	0	0	0	0	0	0
18 ROTTERDAM GAS TURBINES	65	69	62	69	68	68	56	0	0	0	0	0	575
19 ROSETON STEAM (NM SHARE)	175	174	174	174	174	174	174	168	172	174	172	139	3536
20 NM TOTAL THERMAL	2640	2644	2620	2591	2587	2603	2583	2522	2522	2558	2528	2261	52873
21													
22 RANKINE HYDRO	29	36	35	34	36	34	35	21	23	37	35	35	726
23 BUFFALO COLOR (+)	0	0		0	0	0	0	0	0	0	0	0	0
24 KENTS FALLS HYDRO	16	16	16	17	17	17	15	15	20	20	20	15	408
25 CEDARS DELIVERED (N-S+)	79	78	77	78	76	79	78	79	79	79	80	79	1892
26													
27 PASNY NIAGARA (TO NM +)	2262	2239	2159	2190	2267	2127	2132	1867	2030	2095	1870	1710	44036
28 PASNY FITZPATRICK	0	0	0										0
29 PASNY GILBOA (GEN+ PUMP-)	475	724	729	450	500	448	0	0	0	0	0	0	3743
30 PASNY ST LAWRENCE (TO NM +)	867	862	873	862	862	872	865	860	858	862	865	864	20667
31 PASNY TOTAL QUEBEC (TO NM +)	1131	1128	1131	1124	1127	1128	1128	1128	1127	1125	1126	1126	27088
32													
33 CONTROL AREA TOTAL GENERATION	7748	7958	7870	7565	7652	7452	6937	6646	6811	6953	6610	6155	155151
34													
35													

Table CI-3

NMPC SYSTEM GENERATION, TIELINE AND LOAD SUMMARY FOR 6/15/79 24-HR PERIOD

LINE	01	02	03	04	05	06	07	08	09	10	11	12	TOTAL
36													
37 PJM-FALCONER-WARREN 171 (N+S-)	-25	-22	-20		-18	-22	-25	-7	-10	-12	-6	-3	-398
38 PJM-ERIE-DUNKIRK 68 (N+S-)	-209	-157	-120	-114	-109	-114	-184	-151	-172	-175	-179	-168	-4433
39													
40 OH-BECK-NIAGARA PA27 (N+S+)	222	234	241	238	256	256	174	182	95	72	83	99	4030
41 OH-BECK PACKARD 76 (N+S+)	195	207	211	237	221	221	156	169	111	94	102	116	3914
42 OH-ST LAWRENCE-MOSES L33P(N+S+)	187	177	187	134	172	176	166	140	149	144	128	120	3659
43 OH-ST LAWRENCE-MOSES L34P(N+S+)	13[illegible]	132	148	142	147	166	150	114	128	117	96	83	3137
44 OH-BECK TSC105 (N+S+)	12	-8	-10	-11	-9	-6	4	20	32	33	16	20	252
45 OH-BECK TSC106 (N+S+)	32	32	33	34	32	33	34	30	33	37	35	38	863
46 OH-CNP 25HZ (TO CNP+)	5	5	3	4	5	3	4	2	1	3	5	2	86
47 OH-CNP 60HZ (+)	16	14	14	13	13	13	13	17	20	22	22	23	456
48 OH-SLP (TO SLP+)													0
49													
50 NE-WHITEHALL-RUTLAND (E-W+)	23	21	22	19	19	16	17	11	24	27	20	16	577
51 NE-HOOSICK-BENNINGTON (E-W+)	7	4	-17	-20	-20	-20	-5	3	7	11	21	17	126
52 NE-ROTTERDAM-BEAR SWAMP (E-W+)	-44	-55	-144	-151	-152	-148	-93	-43	-36	-21	28	-20	-1239
53 NE-ALPS-BERKSHIRE (E-W+)	-131	-165	-254	-304	-316	-355	-229	-123	-54	-35	-35	-78	-2614
54 NE-PLATTSBURGH-SANDBAR (E-W+)	-100	-95	-98	-98	-99	-103	-110	-106	-94	-100	-98	-98	-2306
55 SENY-LEEDS-PV 345KV 91 (N+S-)													0
56 SENY-LEEDS-PV 345KV 92 (N+S-)	-818	-711	-577	-523	-515	-513	-782	-958	-1068	-1215	-1319	-1244	-23753
57 SENY-PV 115-CON ED (N+S-)	28	34	54	56	60	60	62	36	20	4	-8	-2	540
58 SENY-PV 115-CH (N+S-)	-32	-26	-22	-14	-12	-14	-36	-40	-36	-12	-24	-16	-628
59 SENY-LEEDS-HURLEY (N+S-)	-118	-64	-7	18	24	27	-80	-103	-182	-219	-255	-226	-3369
60 SENY-NORTH CATSKILL (N+S-)	-24	-17	-6	-3	-3	-2	-12	-25	-32	-26	-35	-30	-619
61													
62 NYS-HAMILTON ROAD (N+S-)	-5	-5	-5	-5	-5	-5	-6	-7	-8	-9	-8	-9	-170
63 NYS-BORDER CITY (N+S-)	-42	-35	-35	-37	-32	-33	-42	-47	-64	-66	-65	-64	-1333
64 NYS-STATE STREET (TO NM+)	-31	-31	-33	-44	-43	-37	-34	-44	-64	-62	-66	-56	-1212
65 NYS-SLEIGHT ROAD (-)	-18	-18	-18	-17	-16	-18	-19	-24	-25	-26	-28	-28	-564
66 NYS-CORTLAND (N+S-)	14	8	3	-1	0	3	9	9	0	-2	-3	-2	38
67 NYS-INGHAMS (TO NM+)	-8	-14	-10	-9	-8	-9	-12	-18	-23	-24	-26	-28	-447
68 NYS-FRASER (E+W-)	248	223	206	199	204	208	182	186	84	58	15	3	2797
69 NYS-LOCKPORT (TO NM+)	-34	-21	-16	-13	-13	-11	-10	-21	-35	-47	-48	-45	-711
70 NYS-NIAGARA-ROBINSON (W+E-)	-134	-132	-124	-120	-122	-130	-150	-180	-204	-230	-226	-224	-4540
71 NYS-GARDENVILLE 230KV (W+E-)	-190	-187	-172	-172	-169	-179	-204	-230	-232	-204	-211	-217	-5006
72 NYS-GARDENVILLE 115KV (W+E-)	113	133	134	138	142	142	118	120	126	128	131	135	2908
73 NYS-ERIE STREET (W+E-)	-10	2	10	12	12	13	-5	-12	-26	-32	-30	-26	-490
74 NYS-WALDEN AVENUE (TO NYS-)	-10	-10	-9	-9	-9	-9	-9	-11	-14	-16	-18	-19	-343
75 NYS-COBBLE HILL (TO NYS-)	-4	-3	-5	-3	-3	-3	-2	-6	-4	-5	-9	-6	-128
76 NYS-DEPEW (TO NYS-)	-9	-8	-7	-7	-7	-7	-7	-10	-12	-13	-13	-13	-258
77 NYS-NORTH BROADWAY (TO NYS-)	-15	-14	-12	-12	-12	-12	-14	-16	-20	-22	-23	-23	-463
78 NYS-ANDOVER (N-S+)	-9	-9	-7	-7	-6	-7	-13	-14	-6	-4	-4	-5	-169
79 NYS-CLINTON CORN (TO NYS-)													0

Table CI-4

NMPC SYSTEM GENERATION, TIELINE AND LOAD SUMMARY FOR 6/15/79 24-HR PERIOD

LINE	13	14	15	16	17	18	19	20	21	22	23		
36													
37 PJM-FALCONER-WARREN 171 (N+S-)	-4	-5	-9	-	-13	-21	-30	-24	-23	-25	-27	-20	-308
38 PJM-ERIE-DUNKIRK 68 (N+S-)	-171	-185	-175	-159	-202	-234	-254	-230	-246	-248	-244	-233	-4433
39													
40 DH-BECK-NIAGARA PA27 (N-S+)	105	133	108	102	88	188	185	211	195	173	207	203	4030
41 DH-BECK PACKARD 76 (N-S+)	119	145	123	116	[illegible]	170	[illegible]	197	186	172	195	189	3914
42 DH-ST LAWRENCE-MOSES L33P(N-S+)	126	115	105	107	111	135	149	147	176	180	91	187	3650
43 DH-ST LAWRENCE-MOSES L34P(N-S+)	92	75	61	80	94	130	150	148	191	196	182	181	3137
44 DH-BECK TSC105 (N-S+)	21	19	10	10	6	10	13	27	24	29	0	-10	252
45 DH-BECK TSC106 (N-S+)	37	39	39	40	40	37	37	38	38	40	39	36	853
46 DH-CNP 25HZ (TO CNP+)	3	3	5	4	5	4	5	11	12	-1	-3	-4	86
47 DH-CNP 60HZ (+)	23	23	23	22	22	21	20	20	20	22	21	19	456
48 DH-SLP (TO SLP+)													0
49													
50 NE-WHITEHALL-RUTLAND (F-W+)	21	27	26	27	24	29	39	32	31	28	25	33	577
51 NE-HOOSICK-BENNINGTON (E-W+)	7	9	11	18	16	12	17	14	10	9	8	12	126
52 NE-ROTTERDAM-BEAR SWAMP (F-W+)	-44	-37	-33	-22	-23	-26	-20	-19	-34	-37	-29	-36	-1239
53 NE-ALPS-BERKSHIRE (E-W+)	-91	-19	-9	-6	-35	-28	8	7	-36	-37	-28	-61	-2414
54 NE-PLATTSBURGH-SANDBAR (F-W+)	-96	-88	-87	-100	-91	-82	-87	-86	-95	-99	-98	-98	-2306
55 SENY-LEEDS-PV 345KV 91 (N+S-)													0
56 SENY-LEEDS-PV 345KV 92 (N+S-)	-1151	-1241	-1215	-1154	-1133	-1134	-1017	-1018	-1124	-1094	-1099	-1130	-23753
57 SENY-PV 115-CON ED (N+S-)	6	8	16	12	18	16	12	12	12	12	0	12	540
58 SENY-PV 115-CH (N+S-)	-12	-28	-25	-24	-22	-24	-18	-28	-44	-28	-42	-48	-626
59 SENY-LEEDS-HURLEY (N+S-)	-186	-240	-233	-185	-166	-182	-125	-137	-178	-162	-174	-216	-3369
60 SENY-NORTH CATSKILL (N+S-)	-26	-28	-28	-32	-30	-34	-33	-35	-40	-38	-41	-39	-619
61													
62 NYS-HAMILTON ROAD (N+S-)	-8	-9	-8	-8	-8	-8	-8	-8	-7	-8	-7	-6	-170
63 NYS-BORDER CITY (N+S-)	-65	-67	-63	-61	-63	-64	-67	-61	-66	-69	-66	-59	-1335
64 NYS-STATE STREET (TO NM+)	-60	-61	-65	-55	-59	-55	-56	-47	-50	-64	-50	-50	-1212
65 NYS-SLEIGHT ROAD (-)	-28	-28	-28	-27	-28	-25	-26	-25	-24	-24	-25	-21	-564
66 NYS-CORTLAND (N+S-)	-1	-1	-1	-1	0	-2	-1	2	0	2	0	3	38
67 NYS-INGHAMS (TO NM+)	-23	-23	-21	-20	-21	-25	-25	-23	-19	-22	-22	-14	-447
68 NYS-FRASER (E+W-)	43	-26	-28	47	23	21	107	130	170	151	146	197	2797
69 NYS-LOCKPORT (TO NM+)	-46	-35	-24	-25	-24	-23	-34	-33	-35	-37	-38	-35	-711
70 NYS-NIAGARA-ROBINSON (W+F-)	-224	-230	-226	-222	-222	-230	-220	-202	-208	-210	-194	-176	-4540
71 NYS-GARDENVILLE 230KV (W+F-)	-212	-221	-217	-208	-211	-216	-225	-218	-229	-229	-227	-226	-5006
72 NYS-GARDENVILLE 115KV (W+F-)	128	135	133	126	119	113	95	98	94	98	107	102	2008
73 NYS-ERIE STREET (W+E-)	-28	-32	-28	-26	-31	-37	-42	-31	-36	-38	-36	-35	-690
74 NYS-WALDEN AVENUE (TO NYS-)	-19	-19	-19	-19	-18	-17	-17	-16	-16	-15	-13	-12	-343
75 NYS-COBBLE HILL (TO NYS-)	-6	-7	-7	-7	-6	-5	-8	-5	-6	-6	-6	-6	-178
76 NYS-DEPEW (TO NYS-)	-13	-14	-14	-14	-13	-11	-11	-11	-10	-12	-11	-11	-258
77 NYS-NORTH BROADWAY (TO NYS-)	-23	-24	-24	-24	-24	-23	-22	-21	-21	-22	-21	-19	-483
78 NYS-ANDOVER (N-S+)	-3	-4	-4	-4	-4	-4	-9	-8	-11	-9	-7	-11	-169
79 NYS-CLINTON CORN (TO NYS+)													0

Table CI-5

NMPC SYSTEM GENERATION, TIELINE AND LOAD SUMMARY
FOR 6/15/79 24-HR PERIOD

LINE	01	02	03	04	05	06	07	08	09	10	11	12	TOTAL
80													
81 RGGE 115KV NET (TO NM+)	1'7	138	130	13	139	139	144	169	194	191	192	174	3959
82 RGGE 345KV NET (TO NM+)	-?5	-49	-69	-68	-68	-76	-101	-142	-250	-296	-320	-318	-4838
83													
84 CONTROL AREA NET INTERCHANGE	-818	-592	-803	-377	-320	-332	-959	-1130	-1647	-1932	-2163	-2127	-32485
85													
86 CONTROL AREA SCHEDULE	-5?3	-689	-424	-399	-356	-398	-917	-1100	-1603	-1918	-2174	-2158	-32735
87 CONTROL AREA DEVIATION	111	3	-21	-22	-34	-46	42	30	44	14	-11	-31	-250
88													
89 RANKINE REPLACEMENT (ACTUAL)	49	51	48	48	51	50	51	51	48	48	48	49	1177
90 CNP-OH RESIDUAL(ACTUAL)(TO OH+)	0	0	0	0	0	0	0	18	4	4	0	4	74
91 RANKINE REPLACEMENT SCHEDULE	48	48	48	49	49	49	49	49	49	49	49	49	1138
92 CNP-OH RESID SCHEDULE (TO OH+)	0	0	0	0	0	0	0	15	7	18	4	4	72
93 CNP-OH ADJUSTMENT	1	3	0	-1	2	1	2	-1	2	13	3	0	-13
94													
95 SCHEDULED INADVERTENT PAYBACK													0
96 CONTROL AREA INADVERTENT	112	6	-21	-23	-32	-45	44	29	46	27	-8	-31	-263
97													
98 WEST-CENTRAL TIES (E+W-)	928	817	700	671	664	684	922	999	912	898	831	780	20482
99 SOUTH PERRY (TO RGGE +)	-19	-14	-11	-11	-10	-9	-13	-14	-15	-12	-9	-9	-366
100 STOLLE-MEYER (W+E-)	-157	-142	-127	-119	-117	-122	-168	-191	-192	-187	-182	-175	-4116
101 NM WEST-CENTRAL	781	680	577	556	551	564	754	808	729	719	654	609	16563
102													
103 CENTRAL-EAST TIES (E+W-)	1977	1822	1780	1756	1763	1776	1860	1930	1934	1960	1844	1790	43214
104 NM CENTRAL-EAST	1875	1741	1692	1667	1672	1682	1762	1842	1863	1884	1772	1720	41355
105													
106 LOCKPORT F/C (TO 25HZ -)	9	9	9	9	9	9	9	8	9	9	9	8	211
107 GARDENVILLE F/C (TO 25HZ -)	30	10	8	9	12	11	21	36	38	40	34	37	723
108 HUNTLEY F/C (TO 25HZ -)	0	0	0	0	0	0	0	0	0	0	0	0	0
109 SOUTH BUFFALO F/C (TO 25HZ -)	-3	-4	-4	-3	-4	-3	-4	-4	-5	-4	-5	-5	-100
110 TOTAL F/C (TO 25HZ -)	36	15	13	15	17	17	26	40	42	45	38	40	834
111													
112 WILLIS-MALONE (E-W+)	30	30	32	30	28	30	32	28	30	22	22	22	672
113 WILLIS-BRAINARDSVILLE (E-W+)	-34	-34	-37	-34	-34	-34	-40	-44	-42	-48	-44	-48	-974
114 SARANAC (N+S-)	21	19	20	20	20	20	19	13	8	11	8	9	297
115 ALCOA BUS TIE	44	40	42	37	36	38	50	40	46	33	29	27	1015
116 ADIRONDACK (N-S+)	313	310	318	316	315	320	312	298	305	304	290	286	7326
117 MARCY-EDIC (N-S+)	1119	1119	1133	1129	1126	1137	1097	1047	1062	1052	1030	1027	25772

Table CI-6

NMPC SYSTEM GENERATION, TIELINE AND LOAD SUMMARY
FOR 6/15/79 24-HR PERIOD

LOGP06 SYSTEM POWER LOG FOR [illegible]

LINE	13	14	15	[illegible]	17	18	19	20	21	22	23	24	TOTAL
80													
81 RGGE 115KV NET (TO NM+)	168	167	165	156	162	175	177	175	171	178	186	185	3959
82 RGGE 345KV NET (TO NM+)	-313	-327	-321	-305	-302	-288	-250	-218	-201	-222	-188	-123	-4838
83													
84 CONTROL AREA NET INTERCHANGE	-954	-2101	-2086	-1848	-1913	-1755	-1413	-1235	-1429	-1466	-1391	-1338	-32485
85													
86 CONTROL AREA SCHEDULE	-1998	-2091	-2060	-1895	-1918	-1771	-1411	-1231	-1480	-1551	-1450	-1390	-32735
87 CONTROL AREA DEVIATION	-46	10	18	-51	-5	-16	2	4	-51	-85	-59	-52	-250
88													
89 RANKINE REPLACEMENT (ACTUAL)	49	40	42	42	41	44	41	57	55	40	42	47	1177
90 CNP-OH RESIDUAL(ACTUAL)(TO OH+)	3	0	0	3	0	4	1	6	3	0	2	22	74
91 RANKINE REPLACEMENT SCHEDULE	49	42	47	42	42	42	42	56	56	56	42	47	1138
92 CNP-OH RESID SCHEDULE (TO OH+)	0	4	3	0	0	3	0	4	1	6	3	0	72
93 CNP-OH ADJUSTMENT	-3	2	3	-3	-1	1	-2	-1	-3	-13	1	-22	-13
94													
95 SCHEDULED INADVERTENT PAYBACK													0
96 CONTROL AREA INADVERTENT	-47	12	21	-54	-6	-15	0	3	-54	-95	-58	-74	-263
97													
98 WEST-CENTRAL TIES (E+W-)	826	788	729	799	819	865	989	917	1050	1006	951	957	20482
99 SOUTH PERRY (TO RGGE +)	-10	-9	-8	-9	-13	-21	-24	-22	-26	-25	-26	-27	-366
100 STOLLE-MEYER (W+E-)	-180	-176	-162	-168	-172	-184	-206	-192	-211	-207	-194	-185	-4116
101 NM WEST-CENTRAL	653	617	571	636	656	678	798	739	854	815	776	768	16563
102													
103 CENTRAL-EAST TIES (E+W-)	1867	1618	1487	1610	1566	1623	1762	1757	1944	1927	1885	1976	43214
104 NM CENTRAL-EAST	1794	1553	1421	1530	1496	1566	1700	1694	1868	1850	1809	1892	41355
105													
106 LOCKPORT F/C (TO 25HZ -)	9	9	8	9	9	9	8	9	8	9	9	9	211
107 GARDENVILLE F/C (TO 25HZ -)	38	37	37	37	31	35	42	46	45	47	25	17	723
108 HUNTLEY F/C (TO 25HZ -)	0	0	0	0	0	0	0	0	0	0	0	0	0
109 SOUTH BUFFALO F/C (TO 25HZ -)	-5	-5	-5	-4	-5	-4	-4	-4	-4	-5	-4	-3	-100
110 TOTAL F/C (TO 25HZ -)	42	41	40	42	35	40	46	51	49	51	30	23	834
111													
112 WILLIS-MALONE (E-W+)	24	26	26	20	32	34	34	32	28	26	28	26	672
113 WILLIS-BRAINARDSVILLE (E-W+)	-44	-44	-44	-46	-40	-40	-40	-40	-40	-44	-42	-40	-974
114 SARANAC (N+S-)	8	9	10	12	7	2	2	6	11	12	11	19	297
115 ALCOA BUS TIE	29	29	28	25	57	67	62	58	47	34	69	68	1015
116 ADIRONDACK (N-S+)	293	285	281	284	280	304	304	303	328	332	371	324	7326
117 MARCY-EDIC (N-S+)	1029	1008	998	1005	994	1035	1063	1065	1124	1139	1111	1128	25772

Table CI-7

NMPC SYSTEM GENERATION, TIELINE AND LOAD SUMMARY FOR 6/15/79 24-HR PERIOD

LOGPO7 SYSTEM POWER LOG FOR 166 FRI 06/1[illegible]9 TODAY IS 169 [illegible]

LINE	01	02	03	[illegible]	05	06	07	08	09	10	11	12	TOTAL
118 PASNY-ST LAWRENCE LOAD (-)	688	689	683	[illegible]	688	687	686	697	697	694	702	701	16783
119 PASNY-FITZ STATION SERVICE (-)	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-240
120 PASNY-FITZ INDUSTRIALS (-)	-85	-85	-85	-85	-85	-85	-85	-85	-85	-85	-85	-85	-2040
121 PASNY-NM ST LAWRENCE MUNI (-)	-56	-53	-51	-51	-51	-54	-60	-72	-75	-76	-76	-74	-1613
122 PASNY-NM NIAGARA MUNI (-)	-44	-42	-42	-42	-43	-48	-61	-75	-80	-81	-80	-79	-1545
123 PASNY-JAMESTOWN (-)	-26	-24	-27	-22	-23	-24	-31	-43	-46	-50	-51	-48	-882
124 PASNY LOAD IN CONTROL AREA	909	903	893	900	900	908	933	982	993	996	1004	997	23103
125													
126 HIGH FALLS (N-S+)	0	0											0
127 NYS-WEST LOAD	-13	-12	-11	-11	-11	-12	-14	-16	-18	-18	-20	-20	-388
128 NYS-EAST LOAD	-30	-28	-25	-25	-24	-27	-33	-42	-45	-47	-49	-48	-1027
129 NYS 8 MEASUREMENTS (TO NM+)	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-192
130 NYS LOAD IN CONTROL AREA	85	81	74	73	72	76	94	115	123	126	131	131	2692
131 FOREIGN LOAD IN CONTROL AREA	994	984	967	973	972	984	1027	1097	1116	1122	1135	1128	25795
132													
133 CRT-SLP (TO SLP+)	47	44	43	41	42	40	44	52	61	65	67	70	1394
134 SLP LOAD	47	44	43	41	42	40	44	52	61	65	67	70	1394
135 NM-CNP 25HZ (TO CNP+)	-17	-18	-19	-16	-16	-20	-19	-16	-17	-21	-16	-20	-477
136 CNP LOAD	32	28	27	29	29	23	25	30	33	33	40	34	791
137 DENNISON-CEDARS 1 (N-S+)	7	10	12	13	13	13	11	1	-4	-10	-11	-13	-65
138 DENNISON-CEDARS 2 (N-S+)	25	26	26	25	26	26	25	24	23	22	23	22	543
139 PASNY-NIAGARA NET US DELIVERY	1612	1490	1331	1299	1297	1315	1720	1883	2210	2368	2376	2337	48066
140 NM GILBOA PUMP (-)	-121	-121	-121	-121	-121	-121							-726
141 NM GILBOA GENERATION (+)									152	275	275	275	2054
142 CONTROL AREA LOAD	4244	4106	3962	3913	3937	3978	4401	4946	5503	5690	5764	5794	122666
143 CONSOLIDATED SYSTEM LOAD	3250	3122	2995	2940	2965	2994	3374	3849	4387	4568	4629	4666	96871
144 CORPORATE SYSTEM LOAD	3171	3050	2925	2870	2894	2931	3305	3767	4293	4470	4522	4562	94686
145 EAST CORPORATE LOAD	943	897	866	859	877	865	992	1127	1228	1306	1313	1326	25866
146 CENTRAL CORPORATE LOAD	786	897	734	705	709	739	889	1042	1242	1261	1279	1266	28431
147 WEST CORPORATE LOAD	1442	1384	1325	1306	1308	1327	1424	1598	1823	1903	1930	1970	40389
148 CONSOLIDATED 25HZ LOAD	41	41	42	40	38	40	43	39	53	57	47	49	1093
149 EAST CONTROL AREA LOAD	973	925	891	884	901	892	1025	1169	1273	1353	1362	1374	26893
150 NYS SCHEDULED LOAD	-68	-69	-65	-64	-61	-64	-83	-103	-110	-112	-114	-117	-2316
151 NYS DEVIATION	-4	-6	-9	-6	-4	-3	-7	-6	-5	-2	1	-2	-32

Table CI-8

NMPC SYSTEM GENERATION, TIELINE AND LOAD SUMMARY FOR 6/15/79 24-HR PERIOD

LOGPO8 SYSTEM POWER LOG FOR 166 FRI 06/15/79 TODAY IS 169 MON 6/18/79 TIME 8 39

LINE	13	14	15	[illegible]	17	18	19	20	21	22	23	24	TOTAL
118 PASNY-ST LAWRENCE LOAD (-)	709	709	716	[illegible]	707	705	704	705	701	701	706	713	16783
119 PASNY-FITZ STATION SERVICE (-)	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-240
120 PASNY-FITZ INDUSTRIALS (-)	-85	-85	-85	-85	-85	-85	-85	-85	-85	-85	-85	-85	-2040
121 PASNY-NM ST LAWRENCE MUNI (-)	-74	-74	-74	-73	-73	-73	-73	-73	-73	-73	-69	-62	-1613
122 PASNY-NM NIAGARA MUNI (-)	-77	-76	-74	-72	-71	-70	-67	-65	-69	-70	-63	-54	-1545
123 PASNY-JAMESTOWN (-)	-48	-49	-46	-44	-39	-36	-36	-37	-38	-37	-33	-29	-882
124 PASNY LOAD IN CONTROL AREA	1003	1003	1005	989	985	979	975	975	976	976	966	953	23103
125													
126 HIGH FALLS (N-S+)													0
127 NYS-WEST LOAD	-19	-18	-17	-16	-18	-20	-20	-18	-18	-18	-16	-14	-388
128 NYS-EAST LOAD	-50	-50	-50	-50	-51	-53	-53	-51	-51	-53	-50	-47	-1027
129 NYS 8 MEASUREMENTS (TO NM+)	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-192
130 NYS LOAD IN CONTROL AREA	129	127	125	125	127	136	134	126	126	131	125	100	2692
131 FOREIGN LOAD IN CONTROL AREA	1132	1130	1130	1114	1112	1115	1109	1101	1102	1107	1091	1053	25795
132													
133 CRT-SLP (TO SLP+)	69	69	68	67	68	68	65	64	62	63	60	55	1394
134 SLP LOAD	69	69	68	67	68	68	65	64	62	63	60	55	1394
135 NM-CNP 25HZ (TO CNP+)	-20	-23	-22	-27	-26	-25	-25	-20	-20	-19	-18	-17	-477
136 CNP LOAD	35	39	41	33	37	34	35	32	35	39	35	33	791
137 DENNISON-CEDARS 1 (N-S+)	-12	-12	-13	-11	-13	-11	-10	-8	-6	-7	-4	0	-65
138 DENNISON-CEDARS 2 (N-S+)	22	21	22	22	21	22	23	23	23	23	24	24	543
139 PASNY-NIAGARA NET US DELIVERY	2367	2372	2267	2292	2357	2295	2317	2078	2225	2268	2077	1913	48066
140 NM GILBOA PUMP (-)													-726
141 NM GILBOA GENERATION (+)	275	325	325	152									2054
142 CONTROL AREA LOAD	5794	5857	5784	5717	5739	5697	5524	5411	5382	5487	5219	4817	122666
143 CONSOLIDATED SYSTEM LOAD	4662	4727	4654	4603	4627	4582	4415	4310	4280	4380	4128	3764	96871
144 CORPORATE SYSTEM LOAD	4558	4619	4545	4503	4522	4480	4315	4214	4183	4278	4033	3676	94686
145 EAST CORPORATE LOAD	1325	1193	1121	1127	1151	1144	1093	1069	1062	1079	992	911	25866
146 CENTRAL CORPORATE LOAD	1281	1437	1488	1475	1485	1492	1478	1429	1419	1451	1363	1214	28431
147 WEST CORPORATE LOAD	1952	1989	1938	1901	1886	1844	1744	1716	1702	1748	1678	1531	40389
148 CONSOLIDATED 25HZ LOAD	48	56	49	46	52	45	44	46	48	54	41	34	1093
149 EAST CONTROL AREA LOAD	1375	1243	1171	1177	1202	1197	1146	1120	1113	1132	1042	953	26893
150 NYS SCHEDULED LOAD	-113	-107	-111	-110	-112	-114	-114	-112	-107	-110	-93	-83	-2316
151 NYS DEVIATION	0	4	-7	-2	-2	5	5	-1	-1	1	12	2	-32

NM INADVERTENT SUMMARY

	BRT FWD	REVISED	CUR DAY	TOTAL
ON PEAK	-3585		-230	-3815
OFF PEAK	-239		-33	-272
SUPERVISOR		PRN	ESR	MJM

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Table CI-9

NMPC SYSTEM GENERATION, TIELINE AND LOAD SUMMARY FOR 6/15/79 24-HR PERIOD

[illegible] FRIDAY 15 169 MON 6/18/79 TIME 8 40

LINE	01	02	03	04	05	06	07	08	09	10	11	12	TOTAL
153 CONSOLIDATED SYSTEM LOAD	3250	3122	2995	40	2965	2994	3374	3849	4387	4568	4629	4666	96871
148 CONSOLIDATED 25HZ LOAD	41	41	42	40	38	40	43	39	53	57	47	49	1093
144 CORPORATE SYSTEM LOAD	3171	3050	2925	2870	2894	2931	3305	3767	4293	4470	4522	4562	94686
145 EAST CORPORATE LOAD	943	897	866	859	877	865	992	1127	1228	1306	1313	1326	25866
146 CENTRAL CORPORATE LOAD	786	769	734	705	709	739	889	1042	1242	1261	1279	1266	28431
147 WEST CORPORATE LOAD	1442	1384	1325	1306	1308	1327	1424	1598	1823	1903	1930	1970	40389
98 WEST-CENTRAL TIES (E+)	928	817	700	671	664	685	922	999	912	898	831	780	20482
103 CENTRAL-EAST TIES (W+)	1977	1822	1780	1756	1763	1776	1860	1930	1934	1960	1844	1760	43214
140 NM GILBOA PUMP (-)	-121	-121	-121	-121	-121	-121							-726
142 CONTROL AREA LOAD	4244	4106	3962	3913	3937	3978	4401	4946	5503	5690	5764	5794	122666
149 EAST CONTROL AREA LOAD	973	925	891	884	901	892	1025	1169	1273	1353	1362	1374	26893
136 CNP LOAD	32	28	27	29	29	23	25	30	33	33	40	34	791
134 SLP LOAD	47	44	43	41	42	40	44	52	61	65	67	70	1394
131 FOREIGN LOAD IN CONTROL AREA	994	986	967	973	972	984	1027	1097	1116	1122	1135	1128	25795
84 CONTROL AREA NET INTERCHANGE	-654	-492	-403	-377	-320	-352	-959	-1130	-1647	-1932	-2163	-2127	-32485
86 CONTROL AREA SCHEDULE	-543	-489	-424	-399	-354	-398	-917	-1100	-1603	-1918	-2174	-2158	-32735
87 CONTROL AREA DEVIATION	111	3	-21	-22	-34	-46	42	30	44	14	-11	-31	-250
95 SCHEDULED INADVERTENT PAYBACK													0
93 CNP-OH ADJUSTMENT	1	3	0	-1	2	1	2	-1	2	13	3	0	-13
96 CONTROL AREA INADVERTENT	112	6	-21	-23	-32	-45	44	29	46	27	-8	-31	-263

LINE	13	14	15	16	17	18	19	20	21	22	23	24	TOTAL
153 CONSOLIDATED SYSTEM LOAD	4662	4727	4654	4603	4627	4582	4415	4310	4280	4380	4128	3764	96871
148 CONSOLIDATED 25HZ LOAD	48	56	49	46	52	45	44	46	48	54	41	34	1093
144 CORPORATE SYSTEM LOAD	4558	4619	4545	4503	4522	4480	4315	4214	4183	4278	4033	3676	94686
145 EAST CORPORATE LOAD	1325	1193	1121	1127	1151	1144	1093	1069	1062	1079	992	911	25866
146 CENTRAL CORPORATE LOAD	1281	1437	1486	1475	1485	1492	1478	1429	1419	1451	1363	1214	28431
147 WEST CORPORATE LOAD	1952	1989	1938	1901	1886	1844	1744	1716	1702	1748	1678	1551	40389
98 WEST-CENTRAL TIES (E+)	826	788	729	799	819	845	989	917	1050	1006	951	957	20482
103 CENTRAL-EAST TIES (W+)	1867	1618	1487	1610	1566	1623	1762	1757	1944	1927	1885	1976	43214
140 NM GILBOA PUMP (-)													-726
142 CONTROL AREA LOAD	5794	5857	5784	5717	5739	5697	5574	5411	5387	5487	5219	4817	122666
149 EAST CONTROL AREA LOAD	1375	1243	1171	1177	1202	1197	1146	1120	1113	1132	1042	953	26893
136 CNP LOAD	35	39	41	33	37	34	35	32	35	39	35	31	791
134 SLP LOAD	69	69	68	67	68	68	65	64	62	63	60	55	1394
131 FOREIGN LOAD IN CONTROL AREA	1132	1130	1130	1114	1112	1115	1104	1101	1102	1107	1091	1053	25795
84 CONTROL AREA NET INTERCHANGE	-1954	-2101	-2086	-1848	-1913	-1755	-1413	-1235	-1429	-1466	-1391	-1338	-32485
86 CONTROL AREA SCHEDULE	-1998	-2091	-2068	-1899	-1918	-1771	-1411	-1231	-1480	-1551	-1450	-1390	-32735
87 CONTROL AREA DEVIATION	-44	10	18	-51	-5	-16	2	4	-51	-85	-59	-52	-250
95 SCHEDULED INADVERTENT PAYBACK													0
93 CNP-OH ADJUSTMENT	-3	2	3	-3	-1	1	-2	-1	-3	-10	1	-22	-13
96 CONTROL AREA INADVERTENT	-47	17	21	-54	-6	-15	0	3	-54	-95	-58	-74	-263

NM WEATHER SUMMARY

11AM	W.D.	C.D.	E.D.	4PM	W.D.	C.D.	E.D.	8PM	W.D.	C.D.	E.D.
WETH	FAIR	FAIR	FAIR	WETH	FAIR	P.C.	FAIR	WETH	FAIR	FAIR	FAIR
TEMP	78	82	72	TEMP	83F	87F	85F	TEMP	77F	83F	81F
R.H.	50	53	59	R.H.	42%	45%	53%	R.H.	50%	40%	62%
WIND	SW16	W-16	S-13	WIND	SW16	SW15	S-8	WIND	SW14	SW-8	S-3

Appendix CII

AUTOMATIC LOAD CONTROL OF THE RAQUETTE RIVER DEVELOPMENT BY NIAGARA MOHAWK POWER CORPORATION

This memo describes the logic used to schedule power generation by dispersed storage and generation sources such as the five hydro plants on the Raquette River in upper New York State. This sort of information is useful in scheduling not only multiple hydro plants, but also the other dispersed storage and generation technologies. This memo provides ideas on the nature of some of the logic behind the scheduling algorithm that will be necessary as part of the control and monitoring functi n of dispersed storage and generation.

The Raquette River Development consists of five hydro plants, three of which contain 25 000-kVA generators and two which have generator capacities of 16 000-kVA and 21 500-kVA. The turbines are designed to pass the same quantity of water at best gate, namely, 2800 cfs. Upstream of the five hydro plants, the Carry Falls reservoir with a usable capacity of 57 600 cfs days functions as a regulating reservoir for the entire Raquette River. Because the capacity of the present downriver plants is only 1500 cfs, the Higley reservoir, located between the upper and lower river plants, with a normal use capacity of about 2200 cfs days, is used to reregulate the river flow to accommodate this lower capacity.

When it was decided to place the loading of the five upper river plants under control of the automatic tieline load and frequency control equipment at Syracuse, two methods of loading were considered. The first was to load all five stations simultaneously, with the individual station loads at all times being at the same proportion of their full capacity, that is, each station would be loaded to 20%, 50%, or whatever percentage of the full capacity happened to be required by system conditions. The main disadvantage of this type of operation is that all stations would be loaded at inefficient turbine gate openings for a considerable period of time, which would result in a reduction in the total power generation. The second method was to load the stations in a fixed sequence up to the most efficient turbine gate opening. Under this method, only one unit of the five operates off the peak efficiency point at any one time, resulting in a higher overall efficiency. This method could result in a drain of one or more of the ponds but this is avoided by incorporating a pond limit switch in the control. The limit switch is set for a small range of pond level and automatically switches a station out of its normal sequence position to the last position when the low limit is reached. Further lowering is then delayed until the remaining four stations are loaded.

Accordingly, the equipment in the load control panel at Colton, for loading and unloading the Raquette River plants in response to automatic load control impulses originating in the Power Supervisors

Office at Syracuse, is designed to load the plants in sequence and at the same time maintain all pond levels within a limited range. Normally, the sequence of loading is progressively upstream; that is, South Colton is loaded first, Five Falls second, etc. Unloading is in the reverse order. Whenever a pond level reaches a preset lower limit, that station is removed from its normal sequence position and placed last in the sequence. If two or more ponds are at the low level, the upstream plant is ahead of the downstream plant in the sequence. If all five plants are at low level, the loading sequence is progressively downstream instead of upstream as is normal.

The communication system to accomplish this control consists of an individual telephone circuit between Colton and each of the plants. Each of these telephone circuits handles three channels: a direct current channel for supervisory control and two audio tone channels for the raise and lower impulses for actuation of the waterwheel governor synchronizing motor.

Each of the five plants is fully automatic and under supervisory control from the Potsdam Area District Office at Colton. The supervisory sets for each station are equipped with five positions for use in the automatic load control system. Four of these positions are indication positions which completely reset the supervisory sets after an operation and do not sound an alarm. Three of them indicate turbine gate position, namely, zero, efficient and full gate. The fourth changes the turbine gate position when the pond level reaches either the high or low limit. This position maintains its last indication, either high or low, until the pond reaches the opposite limit, low or high. The fifth supervisory position is a control and indication position for placing the load control at the individual stations into and out of service and is equipped with a bell alarm in the case of a trip at the station.

The communication equipment to receive the load control impulses originating in Syracuse and to retransmit them to the five stations is housed in the load control panel. Two Westinghouse Type FD audio tone receivers, one responsive to 1445 cycles for raise impulses and the other to 765 cycles for lower impulses, key respectively two Westinghouse Type FD audio tone transmitters for retransmission of the impulses from Colton to the plants. The raise transmitter operates at a frequency of 1105 cycles and the lower transmitter, a frequency of 935 cycles. Each of the five stations has audio tone receivers responsive to these frequencies. Raise and lower sequence relays at Colton switch the outputs of these transmitters to only one of the five separate communication channels between Colton and the stations, but both types of impulses are not switched to the same station. That is, raise impulses might be routed to Rainbow Falls and lower impulses to South Colton.

A raise and a lower relay is provided for each of the five stations in the equipment at Colton. These relays are picked up and dropped out in sequence in response to operation of gate limit

and pond level switches at the stations, these operations being reported by supervisory means. Only one relay can be picked up at a time.

The normal loading sequence is South Colton, Five Falls, Rainbow Falls, Blake Falls, and Stark. Provision is made in the equipment for the possible construction of a station at Carry Falls, upstream of Stark. A terminal board in the load control panel at Colton permits reconnection of the raise and lower sequence networks, in but a few minutes, to give any desired sequence.

A typical loading sequence under control of Syracuse might develop as follows, starting with ponds at the high level and all stations at zero gate:

- Raise impulses would be routed to South Colton. Lower impulses would be blocked at Colton until South Colton pulls away from zero gate. At this point, lower impulses would also be routed to South Colton.
- A preponderance of raise impulses carries South Colton to the efficient gate point and trips the efficient gate limit switch. The raise sequence relay for South Colton drops out and that for Five Falls picks up.
- The lower sequence relay for South Colton remains picked up until Five Falls pulls away from zero gate which causes the South Colton relay to drop out and the Five Falls lower sequence relay to pick up.
- A preponderance of raise impulses carries Five Falls to the efficient gate point and then raise impulses are routed to Rainbow Falls. Loading of Rainbow results in the transfer of lower impulses to Rainbow Falls also.
- At this point South Colton and Five Falls are loaded to efficient gate and Rainbow Falls is partly loaded. The Five Falls pond reaches the lower limit. This takes Five Falls out of its normal number two position and places it last, following Stark.
- The raise sequence network will still direct raise impulses to Rainbow Falls but the lower sequence network transfers the lower impulses from Rainbow Falls to Five Falls as Five Falls is last in the sequence and has load. The unloading sequence is the reverse of the loading sequence.
- Five Falls will receive all lower impulses to carry it to zero load and will not receive any raise impulses until all the other four stations are fully loaded. As raise and lower impulses are received more or less continuously from Syracuse, the plant loadings quickly adjust to the condition where Rainbow Falls, immediately above Five Falls, is loaded to the same or to a greater extent than Five Falls. Thus the reduction in the Five Falls pond level is checked and refill to the high limit

is started. When the high limit is reached, Five Falls is switched to its normal sequence position.

The following points summarize the conditions influencing the loading of the plants:

- The normal sequence is fixed but can be changed to any combination of the plants by changing connections on a terminal board.
- Raise or lower impulses can be transmitted to only one station at a time. However, both types of impulses can, but need not, be transmitted to the same station.
- A pond reaching a preset low level would switch the station from its normal position to the last position in the sequence.
- If two stations are at low level, they will be switched to the fourth and fifth positions, the first station of the two in the normal sequence being placed in the fifth position. Thus, with all stations at low pond level, the loading sequence would be reserved.
- When a station reaches efficient gate, raise impulses are switched to the next station in the raise sequence. When a station reaches zero gate, lower impulses are switched to the next station in the lower sequence.

The load control panel, located in the Area District Operators Office at Colton, has the following equipment:

1. A green and white indicating lamp which flashes on receipt of a control impulse from Syracuse; green for lowering impulses and white for raising impulses.
2. A two-position manual station selector control switch for each station. In the "ON" position this switches the station into the loading sequence and in the "OFF" position bypasses the station in the loading sequence. Above each switch, a red and a green lamp in parallel with the indicating lamps of the "Load Control" position on the supervisory set indicate whether the load control at the station is "ON" or "OFF."
3. A "TRIP" and "RESET" manual control switch with spring returns to neutral for placing the load control equipment at Colton into service. The equipment cannot be reset unless the control switch noted in (2) above and the load control at the station are in corresponding positions, that is, "ON" and "ON" or "OFF" and "OFF." The load control will trip with loss of direct current or alternating current control voltage and in the event the load control at any station trips. The load control at the stations will trip with use of the governor control switch, in

case the station trips off the line, with loss of ac or dc control voltage or in case an impulse of overly long duration is received. This trip is indicated by operation of the supervisory with a bell alarm.

4. A two-position manual control switch for transferring the loading range of the five stations from the efficient gate limit up to the full gate limit. In the "OFF" position, the five stations are loaded in sequence only to the point of best efficiency. As this point is reached, the green lamp associated with this switch will go out, a single stroke alarm bell will operate and the red lamp associated with the switch will flash a warning that the upper limit has been reached. With the switch in the "ON" position, the stations will be loaded up to full gate in sequence after they have all reached efficient gate. The stations will all have to be unloaded to the efficient gate point before any unloading below efficient gate will take place. When the transfer point is reached with the switch in the "ON" position, the red lamp will burn steadily and there will be no alarm.

5. A row of green lamps, one for each station under the manual station selector switch. These lamps light in sequence at half brilliance as lower impulses are switched to the station. When an impulse goes to the station, this lamp goes from half to full brilliance for the duration of the impulse.

6. A row of white lamps below the green lamps noted in (5) for indication of raise impulses to the station.

7. A row of green lamps immediately below the white lamps (6) which are lighted when the turbine is at zero gate and are off for all other gate positions.

8. A row of amber lamps below the green lamps noted in (7) which are lighted when the turbine reaches efficient gate and remains lighted between efficient and full gate.

9. A row of blue lamps immediately below the amber lamps noted in (8) which are lighted when the turbine is in the full gate position and are off for all other gate positions.

10. A row of red lamps below the blue lamps noted in (9) which light when the station pond reaches the low limit of the pond range and remain lighted until the pond reaches the high limit of the pond range. When lit, these lamps indicate that the station is not in its normal sequence position.

11. At the top of the panel a Leeds & Northrup recorder shows the net output of the upper Raquette River Plants as measured at Colton on the incoming 115-kV transmission circuit. This recorder also keys a Westinghouse audio tone transmitter for transmission of the output reading to the Syracuse Power Supervisors Office.

12. A Westinghouse audio tone transmitter is also included in the equipment to transmit a reading of the interchange with the Ontario System at the St. Lawrence Substation to Syracuse. This reading is transmitted between St. Lawrence and Colton over a telegraph circuit leased from the telephone company. Thus the communication circuit between Syracuse and Colton will carry four channels: two load control impulse channels between Syracuse and Colton, and two telemeter channels between Colton and Syracuse.

At the Power Supervisors Office in Syracuse load control impulses are generated by a load controller in response to instantaneous values of system frequency biased by the deviation of the net tieline load from the scheduled net tieline load. The bias operates to shift the base frequency as the tieline deviation shifts above or below the schedule. Raise impulses are generated when the system frequency is below this base frequency and lower impulses when above it. When the net tieline load is above schedule for outgoing power or below schedule for incoming power, the base frequency is shifted below 60 cycles. When the net tieline load is below schedule for outgoing power or above schedule for incoming power, the base frequency is shifted above 60 cycles. The amount of bias or shift in the base frequency is set by a rheostat in the bridge circuit of the load controller. This rheostat is calibrated in megawatts per tenth of a cycle. A setting of 15 on this rheostat would cause the load controller to be balanced at the following base frequencies for these deviations of the net tieline load from the schedule:

15 MW over schedule out	59.9 cycles
30 MW over schedule in	60.2 cycles
10 MW under schedule in	59.93 cycles
Net schedule	60.0 cycles

Any variation of the system frequency above or below these values actuates the load controller to generate lower or raise impulses.

The bias setting is determined by the system characteristic which, for a central area that is part of an interconnected system, is the surplus or deficiency in generation within the area due respectively to a drop or rise in frequency caused by a load or generation change in an outside area. This characteristic is a function of the magnitude and type of the load and of the prime mover governor characteristics and operating practices. This surplus or deficiency shows up as load in the tielines between areas. With all control areas in an interconnected system operating on tieline bias control and with the bias set to match the system characteristics, each area controller operates to raise or lower generation in the area only when a load change occurs in the area. A change in generation is made to exactly match the load change and no change is made due to a load change in another

area. However, assistance is given to another area through transient changes in tieline loads above and below the scheduled loads by the amount of the bias setting while generation in the area is being adjusted to match the new load requirements. Thus, in an interconnected system with a number of control areas under the line bias control, each area controller will take care of load changes within its own area but will not operate for load changes occurring in an outside area. This spreads the regulation over a number of stations throughout the system and by taking care of a load change near its source, reduces the swing in tieline loads to a minimum during normal operation. This permits utilization of the tielines at higher average loads and allows closer scheduling of system operations for greater economies in the overall operation of the interconnected system.

The base of 60 cycles for net schedule can also be shifted. This allows operation of the system at average speeds slightly above or below 60 cycles for extended periods in order to gain or lose time. An electric clock connected to the system and set to correct time will continue to provide correct time. If uninterrupted and not separated from the main system, it should never be more than 15 seconds fast or slow. The system is operated to bring the time error to zero at least once each day and the error is seldom allowed to exceed 15 seconds.

Equipment is also provided at Syracuse for transmitting load control impulses to the Oswego Steam Station and to the Lighthouse Hill and Bennetts Bridge hydro stations on the Salmon River. At Oswego the units are loaded proportionally while the hydro plants on the Salmon River are loaded sequentially with pond level control on Lighthouse Hill. The individual units in these two stations are also loaded sequentially, Bennetts Bridge having three units under control and Lighthouse Hill two.

Tieline loads telemetered to Syracuse for incorporation in the control are the tie with the Western Division at Mortimer, the tie with the Eastern Division at Inghams, the net of four ties with the New York State Electric and Gas System in the Central Division, and the tie with the Ontario System of Canada at Massena.

Appendix CIII

GENERAL SERVICE — INCLUDING CUSTOMER GENERATION FROM SAN DIEGO GAS AND ELECTRIC COMPANY SAN DIEGO, CALIFORNIA

As electric utility companies prepare for the possibility of cogeneration in the range up to 10 MW, standard agreements must be worked out between the parties involved. As an indication of the form that such a general service agreement may take, San Diego Gas and Electric has made available Schedule A-5 CG entitled "General Service - Including Customer Generation."

Of particular interest in connection with this general service agreement are such items as rates, which include on-peak, semi-peak, and off-peak categories; facilities charge, which includes a monthly charge for special facilities for parallel operation; interconnection facilities, which are required for the operation of the customer's generator in parallel with the utility's system; and net energy, where the customer cannot be paid for feeding back into the utility's system more energy than the utility supplies the customer; i.e., negative net energy to the customer.

Public Mat.

SAN DIEGO GAS & ELECTRIC COMPANY
SAN DIEGO, CALIFORNIA

Original Cal PUC Sheet No. -E

Canceling Cal PUC Sheet No.

SCHEDULE A-5 CG

GENERAL SERVICE - INCLUDING CUSTOMER GENERATION

APPLICABILITY

Applicable on a voluntary basis to customers who will operate generation facilities (not to exceed 5,000 kw per unit) in parallel with the utility's facilities or serve a portion of their load in isolation from the utility's facilities and are precluded from such operation by the utility's otherwise applicable rate schedule. Applicable to new customers whose billing demand is expected to be between 1,000 kw and 4,500 kw and existing customers whose billing demand exceeded 1,000 kw for three consecutive months in the preceding 12 month period and did not exceed 4,500 kw for three consecutiv months.

TERRITORY

Within the entire territory served by utility.

RATES

	Per Meter Per Month
Customer Charge	$125/mo.
Demand Charge:	
Billing Demand	$4.26 Kw
Net Energy Charge:	
On-Peak	$0.010[illegible]/Kwhr [illegible]
Plus: Semi-Peak	$0.00657/Kwhr [illegible]
Plus: Off-Peak	$0.00457/Kwhr [illegible]

Where time periods are defined as follows:

The definition of time will be based upon the meter reading date for the customer.

Time Period	May 16 - October 15*	All Others
On-Peak	10 a.m. - 5 p.m. Weekdays	5 p.m. - 9 p.m. Weekdays
Semi-Peak	5 p.m. - 9 p.m. Weekdays	10 a.m. - 5 p.m. Weekdays
Off-Peak	9 p.m. - 10 a.m. Weekdays	9 p.m. - 10 a.m. Weekdays

*Where the utility's meter reading schedule would cause more than five of a customer's reads to fall in this period, the first will be based on the All Other Periods.

(Continued)

(To be inserted by utility) (To be inserted by Cal. P.U.C.)

Advice Letter No. -E Issued by JOHN H. W[illegible]Y Date Filed

Decision No. Effective

Resolution No.

SCHEDULE A-5 CG (Continued)

RATES (Continued)

Time Periods:

All time periods listed are in Pacific Standard Time. During periods when Pacific Daylight Saving Time is in operation, one hour must be added to the listed times to arrive at actual "clock" times.

Holidays:

The holidays specified in this schedule are: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day and Christmas Day as designated by California Law.

Facility Charge:

A monthly charge of 1.62% of the installed cost of any special facilities required for parallel operation and new distribution facilities installed to serve facilities normally served by customer generation will be added to the above billing.

Minimum Charge:

The monthly minimum charge shall be $1.67 per kw of maximum demand.

Energy Cost Adjustment:

An Energy Cost Adjustment, as specified in Section 9. of the Preliminary Statement, will be included in each bill for service, including the minimum charge. The Energy Cost Adjustment amount shall be the product of the total energy kilowatt-hours for which the bill is rendered multiplied by $0.03310 per kilowatt-hours. (The Energy Cost Adjustment amount is not subject to any adjustment for serving voltage.)

Franchise Fee Differential:

The franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SPECIAL CONDITIONS

1. Primary Voltage and Energy Discount. A primary voltage and energy discount will only be allowed where delivery is made and energy is received at an available standard voltage. Under these circumstances, the charges before power factor adjustment and energy cost adjustment will be reduced as follows:

3 per cent in the range of 2 kv to 10 kv
4 per cent in the range of 10.1 kv to 25 kv
7 per cent above 25 kv

(Continued)

SCHEDULE A-5 CG (Continued)

SPECIAL CONDITIONS (Continued)

1. Primary Voltage and Energy Discount. (Continued)
The utility retains the right to change its delivery voltage after reasonable advance notice in writing to any customer receiving a discount hereunder and affected by such change, and such customer then has the option to change his system so as to receive service at the new delivery voltage or to accept service without voltage and energy discount after the change in delivery voltage, through transformers owned by the utility.

2. Voltage Regulators. Voltage regulators, if required by the customer shall be furnished, installed, owned and maintained by the customer.

3. Billing Demand. The billing demand will be based on kilowatts of maximum demand as measured each month during the On-Peak Period, provided that the billing demand shall not be less than 90 percent of the maximum on-peak demand registered during the preceeding four months having the same on-peak period. The maximum demand during the On-Peak Period shall be the average kilowatt input during the fifteen-minute interval in which the consumption of electric energy is greater than in any other fifteen-minute interval during the On-Peak Period, as indicated or recorded by instruments installed, owned and maintained by the utility.

In the case of hoists, elevators, furnaces, or other l ds where the energy demand is intermittent or subject to violent fluctuati , the utility may base the maximum demand upon a five-minute interval instead of a fifteen-minute interval.

4. Maximum Demand. The maximum demand in any month shall be the average kilowatt input during that fifteen-minute interval in which the consumption of electric energy is greater than in any other fifteen-minute interval in the month as recorded by instruments installed, owned and maintained by the utility For the purpose of determining the minimum charge the maximum demand shall in no case be less than the highest of (a) 1,000 kw, (b) 80 per cent of the highest maximum demand registered during the preceding eleven months, or (c) the diversified resistance welder load computed in accordance with the utility's Rule 2F-2b.

In the case of hoists, elevators, furnaces and other loads where the energy demand is intermittent or subject to violent fluctuations, the utility may base the maximum demand upon a five-minute interval instead of a fifteen-minute interval.

(Continued)

SCHEDULE A-5 CG (Continued)

SPECIAL CONDITIONS (Continued)

5. Power Factor Adjustment. This schedule is based on service to loads having a maximum reactive kilovolt ampere demand not greater than 75 per cent of the maximum kilowatt demand. In the event that the reactive demand exceeds 75 per cent of the kilowatt demand, the customer shall, upon receiving written notice from the utility, install and operate such compensating equipment as may be necessary to reduce the reactive demand to 75 per cent or less of the kilowatt demand. Unless such correction of reactive demand is made within ninety days, there will be added to each monthly bill following the ninety day period a charge of 15 cents per kilowatt of maximum reactive demand in excess of 75 per cent of the maximum kilowatt demand (whether on-peak or off-peak) for the month.

6. Digital Pulse Recorder Malfunction. In the event that the digital pulse recorded (DPR) malfunctions during the billing period, the energy sales will be based on the mechanical meter reading. Where the malfunction existed for less than 25% of the billing period, the energy sales will be prorated to time periods based on the energy division during the period when the DPR was working properly. Where the malfunction time exceeds 25% of the billing period, the energy sales will be prorated to time periods based on the energy division during the three previous calendar months. If the DPR functions properly for more than 25% of the billing period, the Demand Charge will be based on the maximum demand during the On-Peak Period as measured during the period of correct DPR functioning. In the event that the DPR malfunctions for more than 75% of the billing period, the Demand Charge will be based on the average of the three previous demand charges which have the same On-Peak hours.

7. Reconnection Charge. In the event that a customer terminates service under this schedule and re-initiates service at the same location within 12 months, there will be a reconnection charge equal to the minimum charges which would have been billed had the customer not terminated service.

8. Interconnection Facilities. The customer shall furnish, install, operate and maintain in good order and repair and without cost to the utility, such relays, locks and seals, breakers, automatic synchronizers and other control and protective apparatus as shall be designated by the utility as being required as suitable for the operation of the generator in parallel with the utility's system. In addition, the utility will install, own and maintain a disconnecting device located near the electric meter or meters. The utility shall have the right to disconnect the customer's generating facility at the disconnecting device when necessary to maintain safe electrical operating conditions. Interconnection facilities shall be accessible at all times to utility personnel.

The customer shall notify the utility prior to the initial energizing and start-up testing of the customer-owned generator, and the utility shall have the right to have a representative present at such test.

(Continued)

SCHEDULE A-5 CG (Continued)

SPECIAL CONDITIONS (Continued)

9. Refusal of Standby Service. The utility reserves the right to refuse service to demands normally served by customer generation where supplying such service could endanger continued service to firm customer load.

10. Major Maintenance and Overhaul. The utility will allow the customer reasonable periods, not to exceed one month, for major maintenance and overhaul provided that: 1) such periods shall not exceed one per calendar year and 2) the time and duration of outage are scheduled in advance with the concurrence of the utility. Demands imposed during such periods will not be considered in 90 per cent calculation in Special Condition 3 but may form the basis for billing demand for the maintenance and overhaul period.

11. Net Energy. Net energy is energy supplied by the utility during each time period minus energy generated by the customer during the same time period and fed back into the utility's system at such time as customer generation exceeds customer requirements. Net energy during any time period cannot, however, have a negative value for purposes of determining charges under this schedule.

Appendix CIV

DSG DESIGN AND OPERATING GUIDES FOR SAFE INTEGRATION OF CUSTOMER'S GENERATION INTO THE UTILITY'S DISTRIBUTION SYSTEM, FROM SAN DIEGO GAS AND ELECTRIC COMPANY

To insure proper interconnection and protection of San Diego Gas and Electric Company distribution equipment when a customer wishes to connect electrical generation equipment to a SDG&E feeder, SDG&E will perform the equipment connection in accord with a yet-to-be-agreed-upon company policy. A SDG&E document entitled "Customer Generation" presents the design and operating guides that should be applied to a customer-owned generation system to facilitate safe integration of customer generation into the utility system. The SDG&E document is included in Appendix CIV. The customer is required to pay a monthly charge for at least 5 years to cover the cost of installation, operation, and maintenance of the interconnection.

SDG&E is still developing the details of this guide. This guide will cover: 1) customer design requirements and operating procedures and 2) utility design requirements and operating procedures.

SAN DIEGO GAS AND ELECTRIC COMPANY

CUSTOMER GENERATION

A. INTRODUCTION

1.0 This document presents the design and operating guides that should be applied to a customer-owned generation system to facilitate safe integration of customer generation into the utility's system.

2.0 This guide will cover: 1. Customer design requirements and operating procedures and 2. Utility design requirements and operating procedures.

B. CUSTOMER SYSTEM DESCRIPTION

1.0 The customer may elect to use a variety of energy sources including solar, wind or other exotic sources, in addition to conventional fossil fuels. The end conversion for connection to the utility's system must be into 60 Hz alternating current.

2.0 The customer may elect to run his generator in parallel with the utility or as a separate system with capability of load transfer between the two independent systems. The requirements for these two methods of operation are outlined below:

C. SEPARATE SYSTEM

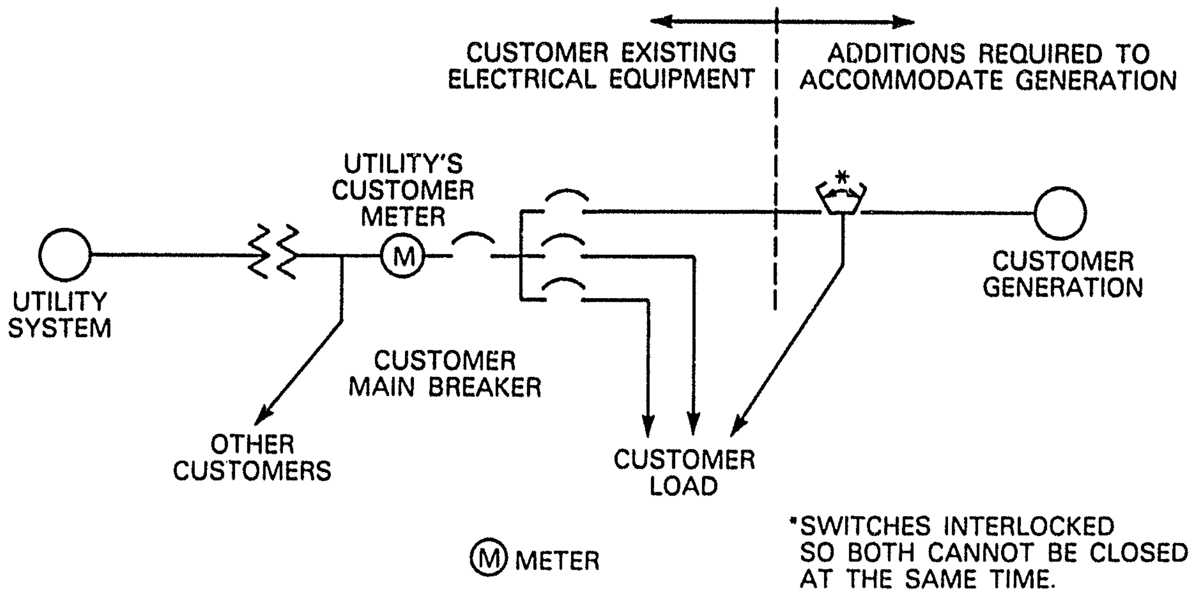
1.0 A separate system is defined as one in which there is no possibility of connecting the customer's generation in parallel with the utility's system. For this design to be practical, the customer must be capable of transferring load between the two systems in an open transition or nonparallel mode. This can be accomplished by either an electrically or mechanically interlocked switching arrangement which precludes operation of both switches in the closed position. A typical schematic diagram is shown below. Design variations are acceptable provided the above requirements are satisfied.

2.0 If the customer has a separate system, the utility will require verification that the transfer scheme meets the nonparallel requirements. This will be accomplished by approval of drawings by the utility in writing and if the utility so elects by field inspection of the transfer scheme. The utility will not be responsible for approving the customer's generation equipment and assumes no responsibility for its design or operation.

3.0 Most Uninterruptible Power Supply (UPS) systems do not specifically meet the separate system criteria. However, if they are not capable of backfeed they will be classified as a separate system. If they can backfeed, they must meet the requirements of parallel generation.

D. PARALLEL OPERATION

1.0 A parallel system is defined as one in which the customer's generation can be connected to a bus common with the utility's system. A transfer of power between the two systems



is a direct and often desired consequence. For this operation to be practical and safe, the following conditions are imposed on the customer's equipment.

E. <u>CUSTOMER GENERATION CAPACITY LESS THAN 20 KILOWATT</u>

1.0 Design Requirements

1.1 The customer's installation must meet all applicable national, state and local construction and safety codes.

1.2 If the customer has generation which can maintain its output when disconnected from the utility system (such as a synchronous generator) the generator should be equipped with the following protective devices:

1.2.1 Individual phase overcurrent trip devices.

1.2.2 Undervoltage trip devices.

1.2.3 Sensitive current unbalance detection and tripping (if a 3φ generator).

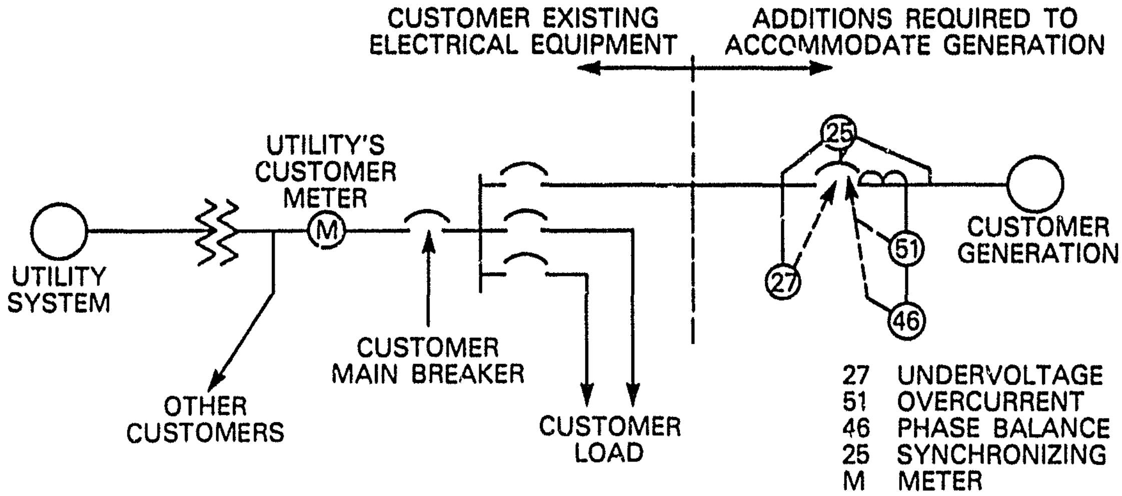
1.2.4 Synchronizing or equivalent controls to ensure a smooth connection with the utility system.

A typical schematic is shown below. Design variations approved by the utility in writing are acceptable provided the intent of the section is met.

1.3 If the customer has generation which cannot maintain its output when disconnected from the utility's system (such as an induction generator), special protective devices may be waived.

1.4 Voltage regulation equipment will be required on the customer's generator to maintain service voltage within normal utility limits.

1.5 The utility reserves the right to require and approve drawings and schematics of the customer's interconnecting equipment and the right of field inspection to verify compliance with design requirements.



2.0 Operating Requirements

2.1 The customer must maintain service voltage within normal utility limits. If high or low voltage complaints or flicker complaints result from operation of the customer's generation, such generating equipment shall be disconnected until the problem is resolved.

2.2 The customer shall not reconnect his generator after a protective device trip unless his system is energized from the utility source or unless he has isolated his system from the utility.

2.3 The customer must agree in writing to discontinue parallel operation when requested by the utility to facilitate maintenance or repair of utility facilities.

2.4 The customer shall be responsible for damage caused to other customers or to the serving utility as a result of misoperation or malfunction of his generator or its controls.

F. <u>CUSTOMER GENERATION CAPACITY GREATER THAN 20 KILOWATT</u>

1.0 Design Requirements

1.1 The customer's installation must meet all applicable national, state and local construction and safety codes.

1.2 The generator shall be equipped with the following protective devices:

1.2.1 Individual phase overcurrent trip devices.

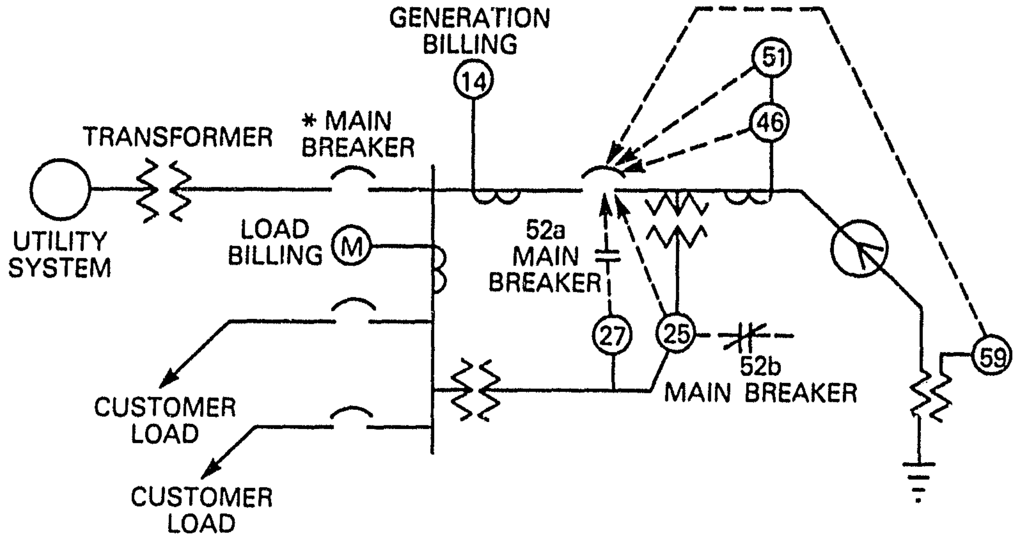
1.2.2 Undervoltage trip device.

1.2.3 Sensitive ground detection.

1.2.4 Sensitive current unbalance detection and tripping.

1.2.5 Synchronizing controls to ensure a smooth connection with the utility system; and interlocks to prevent generator connection if the utility service is de-energized, but to permit the generator to serve its local load.

A typical schematic is shown below. Design variations approved by the utility in writing are acceptable, provided the customer can justify a variance.



*SYNCHRONIZING EQUIPMENT REQUIRED IF CUSTOMER DESIRES TO CLOSE BREAKER WITH BOTH SIDES ENERGIZED.

RELAY IDENTIFICATION

25	SYNCHRONIZING
27	UNDERVOLTAGE
46	PHASE-BALANCE
51	PHASE-OVERCURRENT
52	MAIN BREAKER AUXILIARY SWITCH
59	NEUTRAL OVERVOLTAGE
M	METER

1.3 Voltage regulation equipment will be required on the generator to maintain service voltage within normal utility limits.

1.4 The utility's written approval is required of drawings and schematics of the customer's equipment, and the utility reserves the right to make field inspections to verify compliance with the above requirements.

1.5 A customer whose generation is of significant magnitude so as to affect utility generation or voltage control will be required to install control and monitoring equipment capable of being operated by a supervisory system from the utility's central control office. Such equipment will be specified by the utility. The utility will have priority control over the customer's generation, which will include startup, shutdown, synchronizing and watt and var output.

2.0 Operating Requirements

2.1 The customer must maintain the service voltage within normal utility limits. If high or low voltage complaints or flicker complaints result from operating the customer's generation, such generating equipment shall be disconnected until the problem is resolved.

2.2 The customer shall not reconnect his generator after a protective device trip unless his system is energized from the utility source, or unless he has isolated his system from the utility. To prevent such

hazardous connections, the protective devices specified in B1.2.5 must be provided.

2.3 The customer must notify the company before operating in parallel any generator with an output rating greater than 1000 kVA. This notification must be for each and every connection and disconnection. In addition, the utility will have direct control of certain customer generation, as specified in B1.5.

2.4 The customer shall discontinue parallel operation when requested by the utility to facilitate maintenance or repair of utility facilities.

2.5 The customer will be responsible for damage caused to other customers or to the serving utility as a result of misoperation or malfunction of his generator or its controls.

G. UTILITY SYSTEM DESCRIPTION

1.0 The vast majority of, if not all, customers with generation will be connected to the utility's distribution system. This is a radial system and past experience indicates these loads are of a passive nature. The encouragement of customers to install onsite generation, however, will make backfeed a distinct possibility. The incorporation of protection devices on the customer's equipment cannot be relied upon to prevent all possibilities of backfeed. This is because backfeed can and will occur whenever the customer's generation exceeds his load. Since backfeed is probable, the following design and operating requirements must be incorporated.

2.0 Utility Design Requirements

2.1 A means of disconnection under control of the utility shall be applied to all customers with parallel generation. This can be applied on either the primary or secondary circuit and accomplished with switches, load break elbows, cutouts or secondary breakers. Since existing circuit design incorporates these features, additional costs should be minimal.

2.2 Transformers feeding customers with parallel generation shall be identified with a special tag attached to the transformer or pole. This will notify field crews of the possibility of backfeed. Incoming load data sheets should be flagged and used to initiate orders to tag poles.

2.3 All maps and diagrams used by System Operators to direct switching operations shall have sources of parallel generation identified.

2.4 A supervisory control and monitoring system will be incorporated for those customers specified in Section B1.5.

3.0 Utility Operation Procedures

3.1 As specified in Paragraph G1.0, backfeed from customer generation is a distinct possibility. To maintain safe working conditions, strict adherence to safety rules is required. Paragraph 407 and 411

of SDG&E Accident Prevention Manual are particularly applicable to parallel generation operation. (See Appendix A.)

3.2 The utility will exercise direct control over customer generation that is of sufficient magnitude to affect utility generation and/or voltage regulation. A supervisory system will be provided for this control.

3.3 The utility must have discretionary control over all customer generation independent of magnitude during outages, equipment maintenance or emergencies.

3.4 Additional safety controls or procedures may be required as experience dictates.

Appendix CV

ONE-LINE DIAGRAM OF WIND TURBINE GENERATOR STATION, BREMCO

Figure CV-1 shows a one-line diagram of the station arrangement at Boone, North Carolina. The wind generator operates at 4.16 kV and is connected to the 4.16 kV bus through a main breaker. The main breaker is computer- or operator-controlled. A 2000 kVA transformer steps the voltage up to 12.5 kV at a point one mile from a distribution substation. Auxiliary power is served off the 4.16 kV bus at 208 and 480 V.

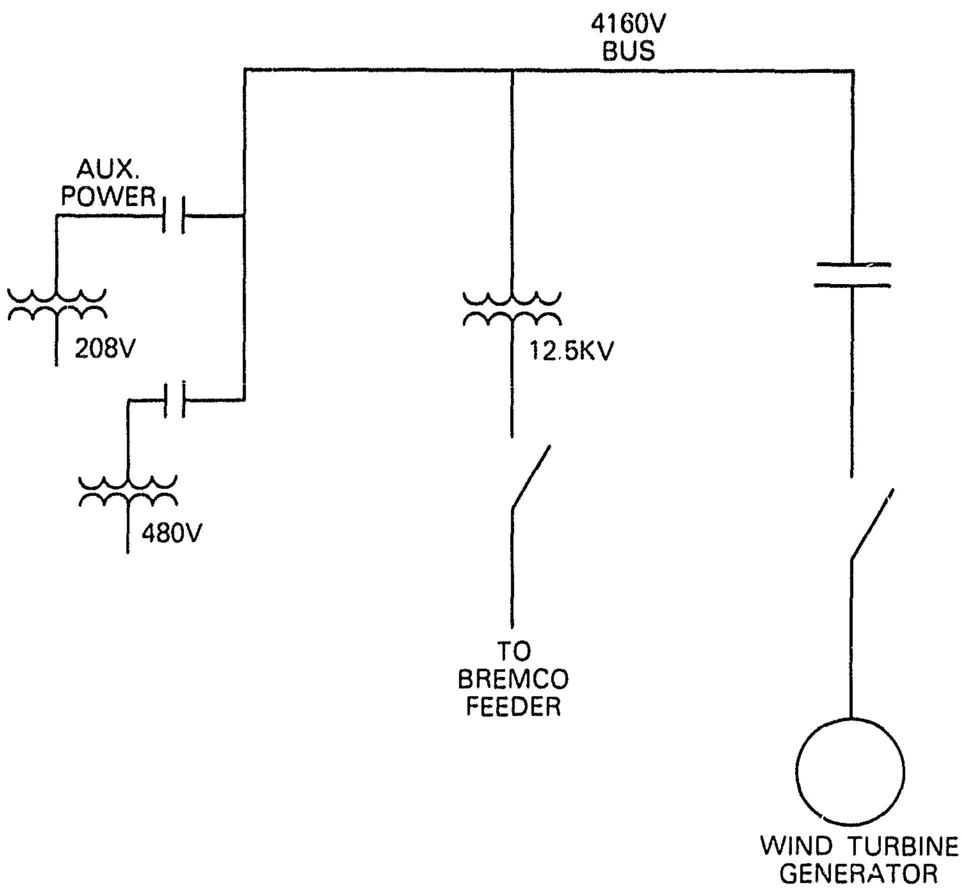


Figure CV-1. Wind Turbine Generator Station One-Line Diagram

Appendix CVI

MONTHLY AVERAGE WIND SPEED AT BOONE, NORTH CAROLINA

Figure CVI-1 shows three different monthly averages for the wind speed in the vicinity of Boone, N.C., where the BREMCO wind turbine generator is located and at the National Weather Site, Charlotte, N.C. The circled points show the monthly average wind speed, at the Boone, N.C., wind turbine generation site, at a 13.6-m sensor elevation. The other data points are for the Charlotte, N.C., National Weather Service site.

For the Boone site, it is primarily during the winter months that the wind is likely to be in excess of 10 mph. Therefore, it will be during this winter period that the wind turbine generator will supply energy to the system. At the time of the GE visit in late September 1979, the wind speed was too low to operate the unit regularly. Fortunately BREMCO has a winter load peaking characteristic. Therefore, on the average, the wind turbine generator should be able to supply energy at the time when the system load is high.

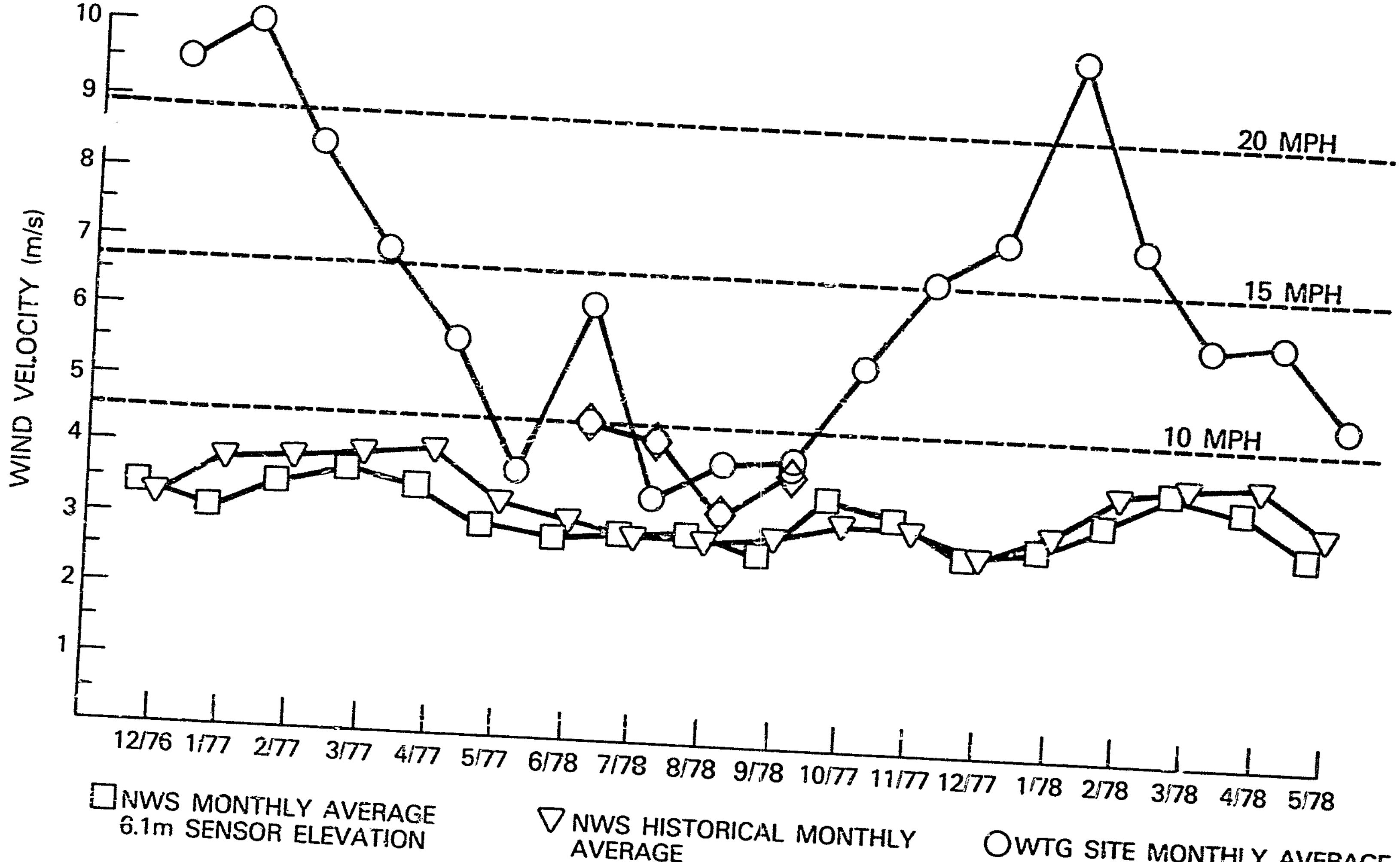


Figure CVI-1. Cognizant National Weather Service Site Comparison of Boone, (WTG)/Charlotte, N.C. (NWS)

Appendix CVII

REPRESENTATIVE DATA TO BE TRANSMITTED FROM REMOTE DSG TO DDC MONITORING SITE

To get an idea of the nature of the data which may be required to be transmitted from a remote dispersed storage and generation site to a distribution dispatch center, refer to Table CVII-1, a list of the quantities monitored at the Blue Ridge Membership Corporation's Howard's Knob wind turbine generator. In Table CVII-1 the following major topics are indicated:

- Wind turbine generator computer status
- Electrical systems
- Electrical system status and alarms
- Master status
- Drive trains
- Yaw drive system
- Pitch control module - hydraulic supply
- Rotor system
- Wind turbine generator system
- Cumulative data

For normal monitoring purposes the amount of data to be transmitted would doubtless be considerably abbreviated. Nevertheless under certain conditions data to the detail noted might be required.

Table CVII-1

QUANTITIES MONITORED AT BREMCO'S HOWARD'S KNOB WIND TURBINE GENERATOR

1. WTG Computer Status

Software mode	Test
Operator mode	Manual
D.A. cycle mode	Auto
Self check	Off
Archive state	On
Archive media	Tape
Current state	Wait
Commanded state	Wait

2. Electrical System

Breaker status	Open
Line frequency	60.01 Hz
Power	39 kW

Table CVII-1 (Cont'd)

2. <u>Electrical System</u> (Cont'd)

Voltage line A-B	5.1 V
Current main A	0.0 A
B	-0.1 A
C	-0.1 A
Auxiliary	7.5 A
<u>Generator</u>	
Voltage A-B	25.6 V
Exciter current	-0.2 A
Temperatures A	83 °F
BR1	61 °F
BR2	58.6 °F
Power setting	0.0 kW
Shaft speed	1.0 rpm

3. <u>Electrical System Status and Alarms</u>

Main breaker	Open
Lockout relay	Norm
Sync enable	Off
Pitch starters	
charge	On
slew	On
Yaw starter pump	Off
Lube starter pump	On
<u>Transformer</u>	
Temperature	Norm
Ground	Norm
Aircraft beacon 1	On
Aircraft beacon 2	On

4. <u>Master Status</u>

Operator mode	Manual
Wind speed	
Instant	18.8 mph
Average	18.8 mph
Wind direction	
Instant	34.5°
Average	29.8°
Blade pitch	96.4°
Rotor speed	25.0 rpm
Generator speed	1.0 rpm
<u>Power</u>	39.0 kW
	5.1 V

Table CVII-1 (Cont'd)

5. Drive Train

Rotor position	268.2°
Rotor speed	25.0 rpm
Generator speed	1.0 rpm
Generator power	39.0 kW
Shaft vibration	0.056 g's
Shaft brake	
Status	On
Accumulator	ALRM
Pressure	Norm
Hydraulic pump	
Status	Off

6. Yaw Drive System

Average wind speed	17.7 mph
Wind direction	
Instant	20.8°
Yaw drive	Off
CW drive	Off
CCW drive	Off
Yaw pump	Off
Oil level	Norm
Pump alarm	Fail
Yaw brake	ENAB
Brake alarm	ALRM
Yaw brake accumulator	Off

7. PCM Hydraulic Supply (Pitch Control Module)

PCM oil level	Norm
Pressure alarms	
Odd feather accumulator	Norm
Even feather accumulator	Norm
Main accumulator	Norm
Emergency feather	
Even	On
Odd	On
PCM auto	Off
PCM manual	Off
Slew pump	On
Slew pump alarm	Norm
Charge pump	On
Blade pitch 1	96.4°
Blade pitch 2	96.4°

Table CVII-1 (Cont'd)

8. Rotor System

Bearing oil flow	On
Bearing vibration	0.544 g's
Rotor shaft speed	25.0 rpm
Rotor position	268.2°
Trans oil temp	70.2°
Nacelle temp	71.4°

9. WTG System

Current state	Wait
Commanded state	Wait
Wind speed	
Instant	20.0 mph
Average	14.8 mph
Wind direction	
Instant	40.3°
Average	33.0°
Main breaker	Open
Generator power	39.0 kW
Rotor speed	25.0 rpm
Blade pitch	96.4°
Feather latch	LTCH
Security system	Off
Enclosure temp	70.5°
Nacelle temp	71.4°

10. Cumulative Data

Elaspsed time	0.0000 hr
Generated	0.0000 kWltrs
	0.0000 kvar hr
Auxiliary	0.0000 kWA hr
Electrical efficiency	0.0000
wind hours	0.0000 mph
Average kW per mph	0.0000
Main breaker operations	
Total operations	0.0000
Operations per hour	0.0000
Operations over 120%	0.0000

Appendix CVIII

ECONOMIC ASSESSMENT OF THE UTILIZATION OF LEAD-ACID BATTERIES IN ELECTRIC UTILITIES, PSE&G

One purpose of the visits to electric utility companies was to obtain information on the economic assessment methods of the utilization of various DSGs in an electric utility system. An example of this sort of economic assessment was obtained during the visit to the Public Service Electric and Gas Corporation in a PSE&G report entitled "Economic Assessment of the Utilization of Lead-Acid Batteries in Electric Utility Systems." Quoting from the objectives of this study:

> "The purpose of this report is to search for and identify specific applications where lead-acid batteries might be competitive. Particular attention is given to searching of the PSE&G system for installations of batteries which could defer or cancel costly transmission projects. Promising transmission applications are assessed and an analysis of all potential battery savings including those on the generating, transmission, and distribution system is made. The potential savings are compared with the cost of installing the batteries."

The material which follows presents an executive summary of the PSE&G report and compares prospective applications for the PSE&G transmission and distribution system with an alternative method of supplying a comparable service using batteries.

This analysis of the economic assessment indicates first that for the conditions studied, the use of lead-acid batteries is not "presently competitive for wholesale electric utility applications."* It also shows that there are conditions (developed from a sensitivity analysis) that indicate more favorable results could be obtained with lead-acid batteries.

In the long run other batteries having more favorable cost characteristics could be analyzed in a similar fashion. Presumably the methods outlined here would be suitable for identifying favorable cost benefit relations for improved batteries.

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*"Economic Assessment of the Utilization of Lead-Acid Batteries in Electric Utility Systems," HCP/T-28571, Public Service Electric and Gas Company, Nov. 1977. This report was prepared for, funded by, and published by U.S. DOE.

PSE&G REPORT
EXECUTIVE SUMMARY

INTRODUCTION

The purpose of this study is to search for and identify specific applications in which lead-acid batteries might be economically competitive on an electric utility system. Particular attention is given to searching the PSE&G system for installations of batteries which could defer or cancel costly transmission and/or distribution projects. Although the transmission and distribution data are based on specific applications on the PSE&G system, the generation data are based on a national reference system. This system was developed in RP-729-1 "Economic Assessment of the Utilization of Fuel Cells in Electric Utility Systems" which was prepared by PSE&G for EPRI. Data on lead-acid battery costs and characteristics were provided by ERDA. The Report analyzes and summarizes all costs and savings attributable to lead-acid batteries.

GENERAL APPROACH

The general approach used in the battery assessment is to first identify specific applications for the PSE&G transmission and distribution system. The amounts and required characteristics of lead-acid batteries to satisfy the needs of the transmission applications are determined.

Having determined the amount of batteries required, this battery capacity is substituted for alternate peaking and intermediate type generating capacity. All costs and savings associated with the batteries are then analysed including the following:

- Battery capital cost
- Transmission and distribution saving
- Production cost saving
- Spinning reserve saving
- Alternate capacity saving
- Quick lead time saving
- Generating reserve requirement saving
- Losses
- Reactive capacity

The underlying methodology in which all costs and savings are equated in comparable terms is the "minimum revenue requirement" discipline. This methodology, which is very commonly used in the electric utility industry, is explained in several standard textbooks on Engineering Economics. In this report, the methodology has been used to calculate all costs and savings in terms of "present worth of all future revenue requirements" (pwafrr), using a cost of money (interest rate) of 10%. Costs and savings are finally summarized in terms of equivalent $/kW cost of batteries.

BASIC CONCLUSIONS

1) With the base data, total savings could not be identified which could justify installation of lead-acid batteries in spite of very substantial transmission savings.

2) Several parameters were found which, if for a particular utility are substantially different from those used in this report, could result in justification of lead-acid batteries. In general a utility should have a combination of the following characteristics:

   (a) A relatively large percentage of nuclear capacity.

   (b) A large differential between fuel prices for base load units and for peaking units.

   (c) An application resulting in large transmission savings.

3) Continuing inflation and the recognition by utilities that there will be a continuing inflation will make the economics of lead-acid batteries more attractive. In particular, a reasonable differential between fuel prices for base load units and for peaking units will make batteries economically competitive.

TRANSMISSION SAVINGS (See Appendix C for Methodology)

The PSE&G transmission system development is typically planned to provide the transmission capability to satisfy various functional requirements. One of these requirements is the delivery of emergency power to the system or a sub-area of the system and is called the Capacity Emergency Transfer Objective (CETO). The ability of the transmission system to deliver this emergency power is termed the Capacity Emergency Transfer Limit (CETL).

Batteries sited in the PSE&G system or a sub-area of the system would have the effect of reducing the system's or sub-area's CETL. By locating sufficient batteries in an area, it would be possible to defer transmission projects planned primarily for CETL/CETO reasons.

A survey of the planned transmission developments in the 1977-87 periods reveals that three specific underground transmission projects, which would provide increased CETL capacity to the generation deficit Northern Zone of the PSE&G system (Figure ES-1), could potentially be deferred by the installation of battery capacity. Also, by locating a portion of these batteries in the Fair Lawn load area within the Northern Zone, an additional underground transmission project could be deferred. The existing Northern Zone transmission system and those facilities identified as deferment candidates are shown in Figure ES-2.

Starting with the base system CETL/CETO conditions for the PSE&G Northern Zone (no battery installations) and knowing

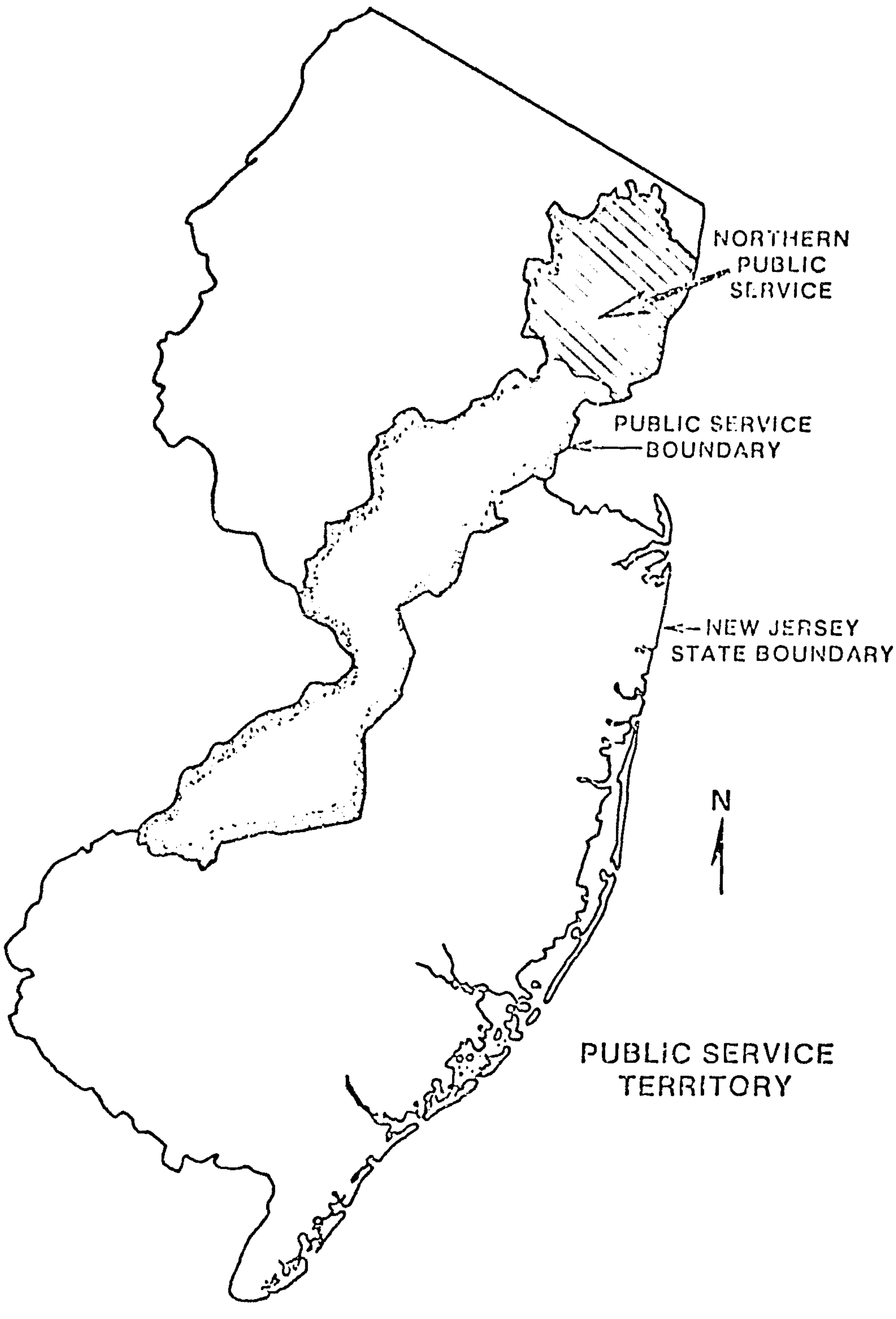
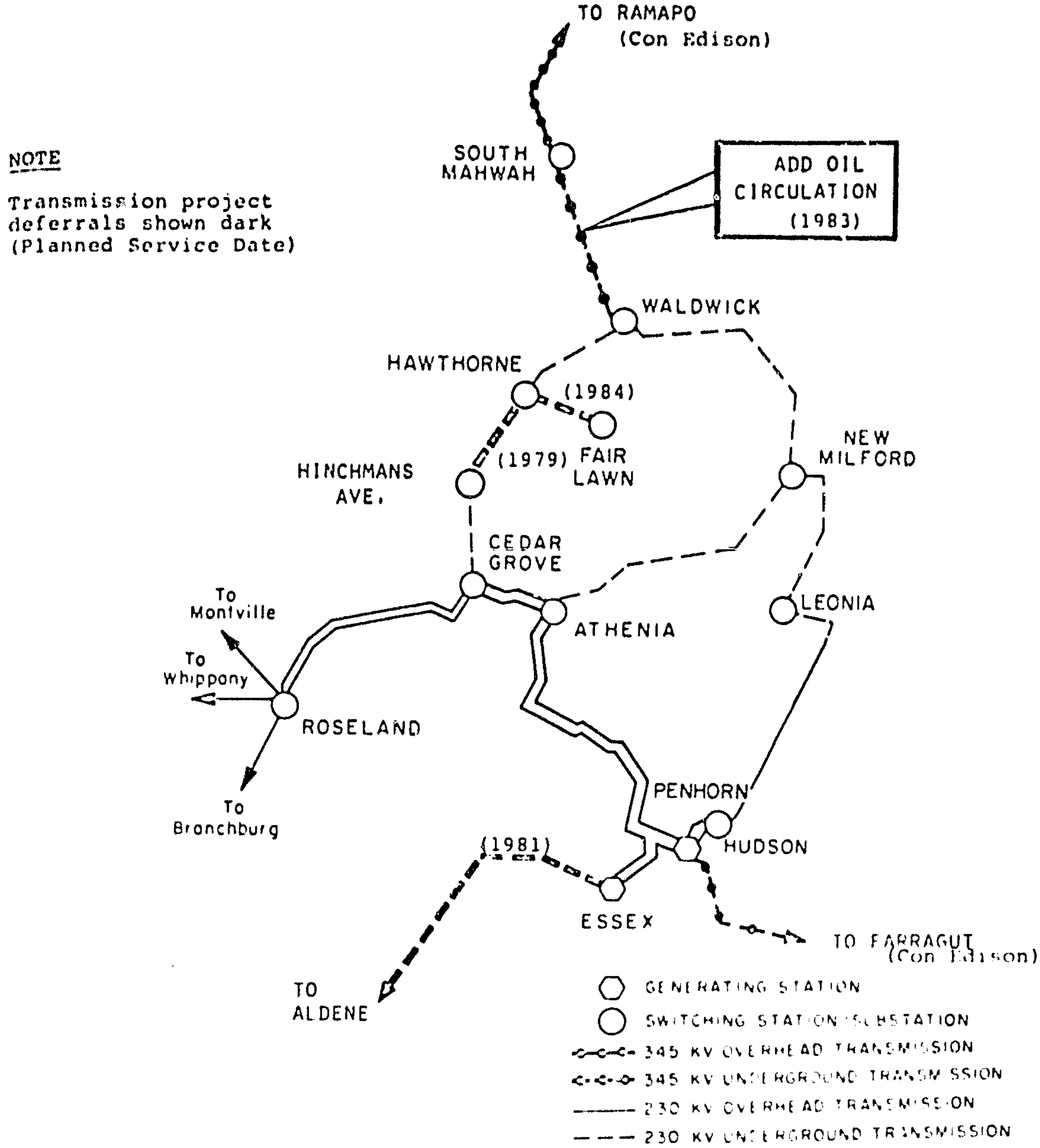

NORTHERN PUBLIC SERVICE
PUBLIC SERVICE BOUNDARY
NEW JERSEY STATE BOUNDARY
N
PUBLIC SERVICE TERRITORY

Figure ES-1



1976 PSE&G NORTHERN ZONE

230 AND 345-KV TRANSMISSION

Figure ES-2

the CETL increase associated with each transmission deferral candidate as well as the potential CETO reduction accruing from a given amount of battery capacity installation, a simple relationship can be developed stating the specific transmission project deferrals possible as a function of the amount of batteries installed. From this generalized relationship, three specific quantity/location applications were formulated based on CETL/CETO requirements. These applications were then adapted to obtain the secondary benefit resulting from the location of some of the required Northern Zone battery installation specifically in the Fair Lawn load area to permit delay of that area's planned reinforcement. The three applications and their associated deferrals are summarized in Table ES-1. The transmission savings derived from the most promising application are shown in Table ES-2.

It was assumed that batteries installed to provide emergency transmission and distribution protection would normally operate on a system economic dispatch basis. Therefore, the load cycle characteristics of the Northern Zone and Fair Lawn load area were compared to the PSE&G system load cycle to assure that the batteries, operating on a system basis, would be sufficiently charged to provide the necessary protection.

DISTRIBUTION SAVINGS

Having identified the most promising application of batteries in the PSE&G system and having quantified the number of MW required, we investigated the additional savings achievable from locating these batteries at distribution substations. These additional savings are derived from the postponement of planned substations in the 1979-1985 period and from the postponement of unidentified substations required in the post-1985 period.

These savings are summarized on Table ES-3. Further savings from applying batteries at the ends of primary and secondary distribution circuits are achievable but installation of the batteries on these circuits is judged to be not feasible.

GENERATION COSTS AND SAVINGS

The 1980 load and capacity data for the Reference System are shown in Table ES-4. The generating units selected for the expansion of the Reference System are shown in Table ES-5. The fuel prices used for the study are shown in Table ES-6.

The capital costs, fuel prices, and most of the generating unit operating characteristics were supplied by EPRI. The Reference System expansion is shown in Figure ES-3 as an optimum generation mix. Optimum generation mix is that combination of generating units which minimizes the present worth of all future revenue requirements for capital related charges and production cost (fuel, operation, and maintenance). The optimum mix for the Reference System does not contain enough nuclear capacity to provide nuclear charging energy for lead-acid batteries.

Table ES-1

TRANSMISSION DEFERRALS FROM BATTERY ADDITIONS

Application	Battery Additions (MW)	Battery Additions (YEAR)	Facilities Deferred	Planned Service Date (YEAR)	Deferred Service Date (YEAR)	Estimated Capital Cost (current) ($x1000)
1 (1)	85	1979	a. Hawthorne-Hinchmans 230-kV cable and Waldwick 230-kV 600 MVA PAR (2)	1979	1980	5,900
			b. South Mahwah-Waldwick 345-kV cable oil circulation equipment	1983	(3)	700
			c. Hawthorne-Fair Lawn 230-kV cable and Fair Lawn 230/138-kV autotransformer	1984	1987	5,300
2 (4)	85	1979	a. Hawthorne-Hinchmans 230-kV cable and Waldwick 230-kV 600 MVA PAR	1979	1980	5,900
	85	1981	b. South Mahwah-Waldwick 345-kV cable oil circulation equipment	1983	(3)	700
			c. Hawthorne-Fair Lawn 230-kV cable and Fair Lawn 230/138-kV autotransformer	1984	1988	5,300
			d. Aldene-Essex 230-kV cable and Essex 230-kV 600 MVA PAR	1981	1982	26,200
3 (5)	85	1979	a. Hawthorne-Hinchmans 230-kV cable and Waldwick 230-kV 600 MVA PAR	1979	1982	5,900
	110	1980	b. South Mahwah-Waldwick 345-kV cable oil circulation equipment	1983	(3)	700
	190	1981	c. Hawthorne-Fair Lawn 230-kV cable and Fair Lawn 230/138-kV autotransformer	1984	1988	5,300
	55	1983	d. Aldene-Essex 230-kV cable and Essex 230-kV 600 MVA PAR	1981	(3)(6)	26,200

Notes

(1) Approximately 75 MW of the total 85 MW must be located in the Fair Lawn load area
(2) PAR - Phase Angle Regulator
(3) Deferred indefinitely beyond 1987
(4) Approximately 150 MW of the total 170 MW must be located in the Fair Lawn load area
(5) Approximately 150 MW of the total 440 MW must be located in the Fair Lawn load area
(6) It would cost approximately $200,000,000 to install enough batteries to indefinitely defer the Aldene-Essex project ($26,200,000).

Table ES-2

TRANSMISSION SAVINGS ANALYSIS APPLICATION 3

Service Date	1979	1981	1983	1984
Capital Cost Cancelled or Deferred (million dollars)	5.9	26.20	0.7	5.3
Cancel or No. of Years Deferred	3	cancel	cancel	4
CCIF	1.05	1.05	1.05	1.05
Annual Carrying Charges, %	15	15	15	15
Levelized Annual Revenue Requirements (million dollars/year)	.93	4.13	.11	.83
Pwafrr Saving (1979 million dollars)	2.54	34.10	.75	1.79
Pwafrr Cumulative Saving 1979 to 1984		$39.18 million		

Table ES-3

DISTRIBUTION SAVINGS ANALYSIS

	Application 3		
Service Date	1981	1990	1991
Capital Cost Cancelled or Deferred (million dollars)	1.74	3.48	6.96
No. of Years Deferred	3	3	3
CCIF	1.05	1.05	1.05
Carrying Charges, %	15	15	15
Levelized Annual Revenue Requirements (million dollars/year)	.27	.55	1.10
Pwafrr Savings	.61	.53	.96
TOTAL Pwafrr Cumulative Saving		$2.1 million	

Table ES-4

1980 REFERENCE SYSTEM CHARACTERISTICS

PEAK LOAD: 6000 MW, Summer

LOAD FACTOR: 60%

GROWTH RATE: 6% Per Year, Load and Energy

INSTALLED CAPACITY: 7200 MW

INSTALLED RESERVES: 20%

	Nuclear	Coal Steam	Oil Steam	Gas Turbine	Conventional Hydro	Pumped Storage Hydro
Total Capacity	800 MW	3200 MW	1800 MW	600 MW	600 MW	200 MW
Capacity Mix	11.1%	$\underbrace{44.4\% \quad 25.0\%}_{69.4\%}$		8.3%	8.3%	2.8%
Projected (1) 1980 Mix for U.S.	13.2%	65.3%		9.4%	9.8%	2.3%

(1) EEI National Power Survey, April 1975.

Table ES-5

REFERENCE SYSTEM EXPANSION*

Type of Generating Unit	Capacity (MW)	1975 Capital Cost ($/kW)
Nuclear	800	540
Oil Intermediate	400	240
Combined Cycle	250	210
Gas Turbine	150	120

*RP-729-1, "Economic Assessment of the Utilization of Fuel Cells in Electric Utility Systems," EPRI.

Table ES-6

REFERENCE SYSTEM FUEL COSTS DATA PROVIDED BY EPRI

Fuel	1980 Fuel Price (1975 $/MBtu)
Nuclear	0.60
Coal	1.20
Oil #6	2.05
Oil #2	2.45

RP-729-1, "Economic Assess. .nt of the Utilization of Fuel Cells in Electric Utility Systems."

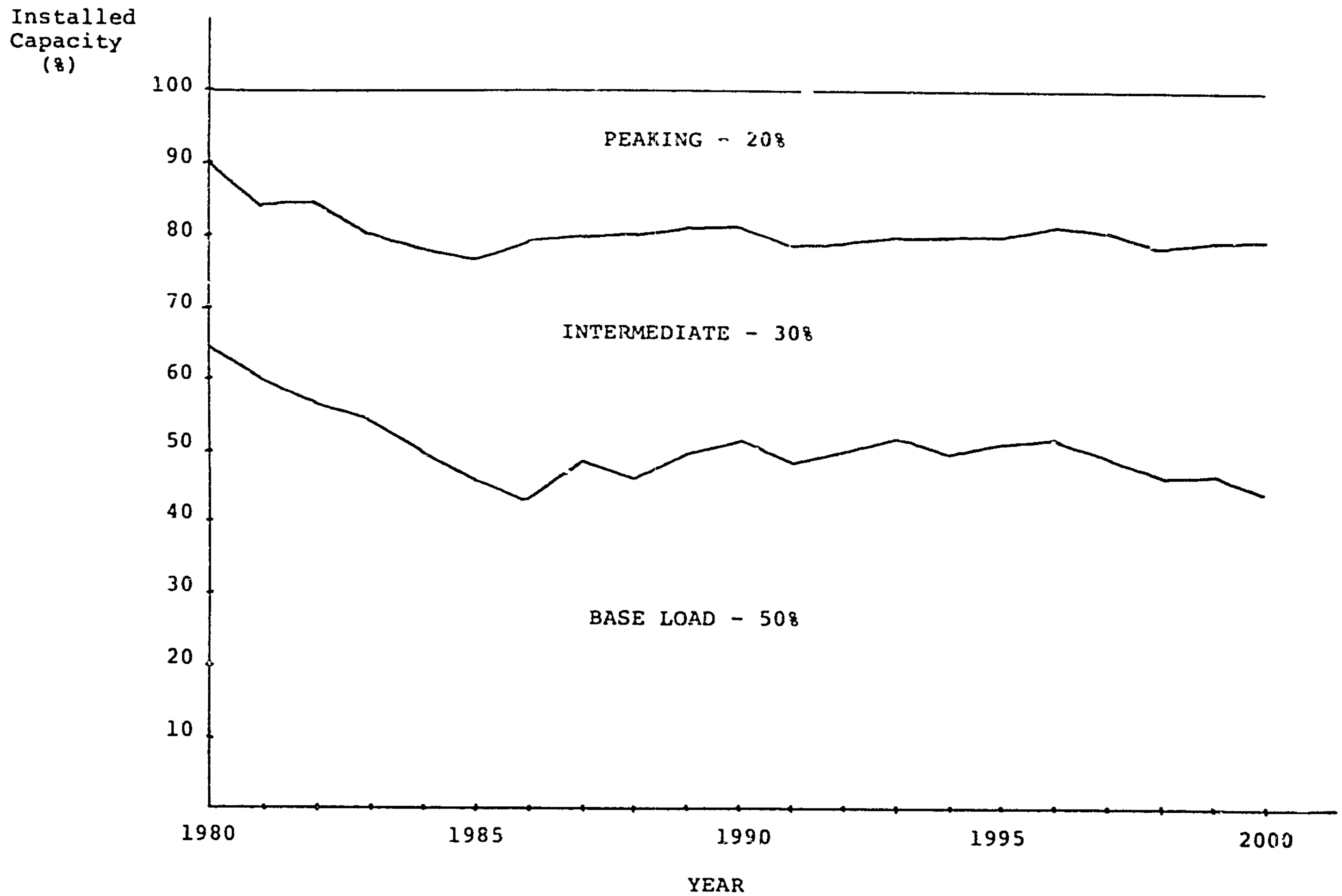


Figure ES-3. Optimum Nuclear Expansion Generation Mix

The lead-acid battery data are shown in Table ES-7. These data were supplied by ERDA. The capital cost is primarily a function of energy storage capability, rather than MW size as is typical of most other types of generating capacity.

The carrying charges for the battery portion of the plant have been calculated as a function of battery life, and are shown in Figure ES-4.

Conventional generating units are available only in relatively large, discrete sizes. The size and schedule of the battery installations determined in Section 3 does not allow an exact MW for MW replacement of capacity in the Reference System. The generation analysis considers two possible replacement scenarios:

1. Replace 500 MW of gas turbine peaking capacity with 440 MW of lead-acid batteries.
2. Replace a 400 MW oil steam intermediate unit with 440 MW of lead-acid batteries and postpone 350 MW of gas turbine peaking capacity for periods of one to three years.

Table ES-8 summarizes the generation capital costs and savings for the replacement of gas turbine or oil steam capacity with lead-acid storage batteries. Table ES-9 summarizes the production cost savings and penalties for the replacement of gas turbine or oil steam capacity with lead-acid storage batteries. The combined capital and production cost savings and penalties show that the replacement of gas turbine capacity is the least costly alternative by a pwafrr of $38 million.

The outage rates of lead-acid batteries are projected to be significantly lower than gas turbine units. Therefore, the replacement of gas turbines with batteries would result in reduced installed capacity reserve requirements and an associated capital cost saving.

However, the limited energy constraint of lead-acid batteries may reduce their load carrying capability, thereby increasing reserve requirements. Figure ES-5 shows an estimate of battery load carrying capability as a function of the amount of battery capacity installed. The net effect of battery availability and limited energy is to reduce the Reference System reserve requirement by approximately 60 MW. Capital cost savings for this amount of capacity are already included in the analysis (440 MW of batteries replaced 500 MW of gas turbines).

The construction lead time required for lead-acid batteries is projected to be two years, compared to longer lead times required for all other types of capacity except gas turbines. The Pwafrr savings due to batteries short lead time is zero with respect to gas turbines and $16 million with respect to oil steam units. These savings are included in the capital cost analysis.

Table ES-7

CAPITAL COSTS AND OPERATING CHARACTERISTICS
OF LEAD-ACID STORAGE BATTERIES

CAPITAL COSTS

Initial Investment	10-Hour Battery	5-Hour Battery	3-Hour Battery
Installed Cost ($/kW)			
Battery Costs	368	184	111
Other Energy Related Costs	284	142	85
Converter Costs	74	74	74
Total	726	400	270
Lead Time (years)	2	2	2
CCIF	1.05	1.05	1.05
Estimated Life (years) (Exclusive of Batteries)	30	30	30
Carrying Charges (exclusive of Batteries)	15	15	15
Battery Replacement			
($/kW)	276	138	83
Estimated Life	2000 cycles up to 14 years		
Carrying Charges	Determined as a function of life		
OPERATING CHARACTERISTICS			
Efficiency (%)	75	70	65
Charging Time (hours)	10/13	5/7/10	3/5/10
Charging Capacity (% of rated load)	133/100	143/100/71	154/100/46
Fixed O&M		None	
Variable O&M (mills/kWh)	0.5	0.5	0.5
Forced Outage Rate (%)	4	4	4
Annual Maintenance (week/year)	1	1	1

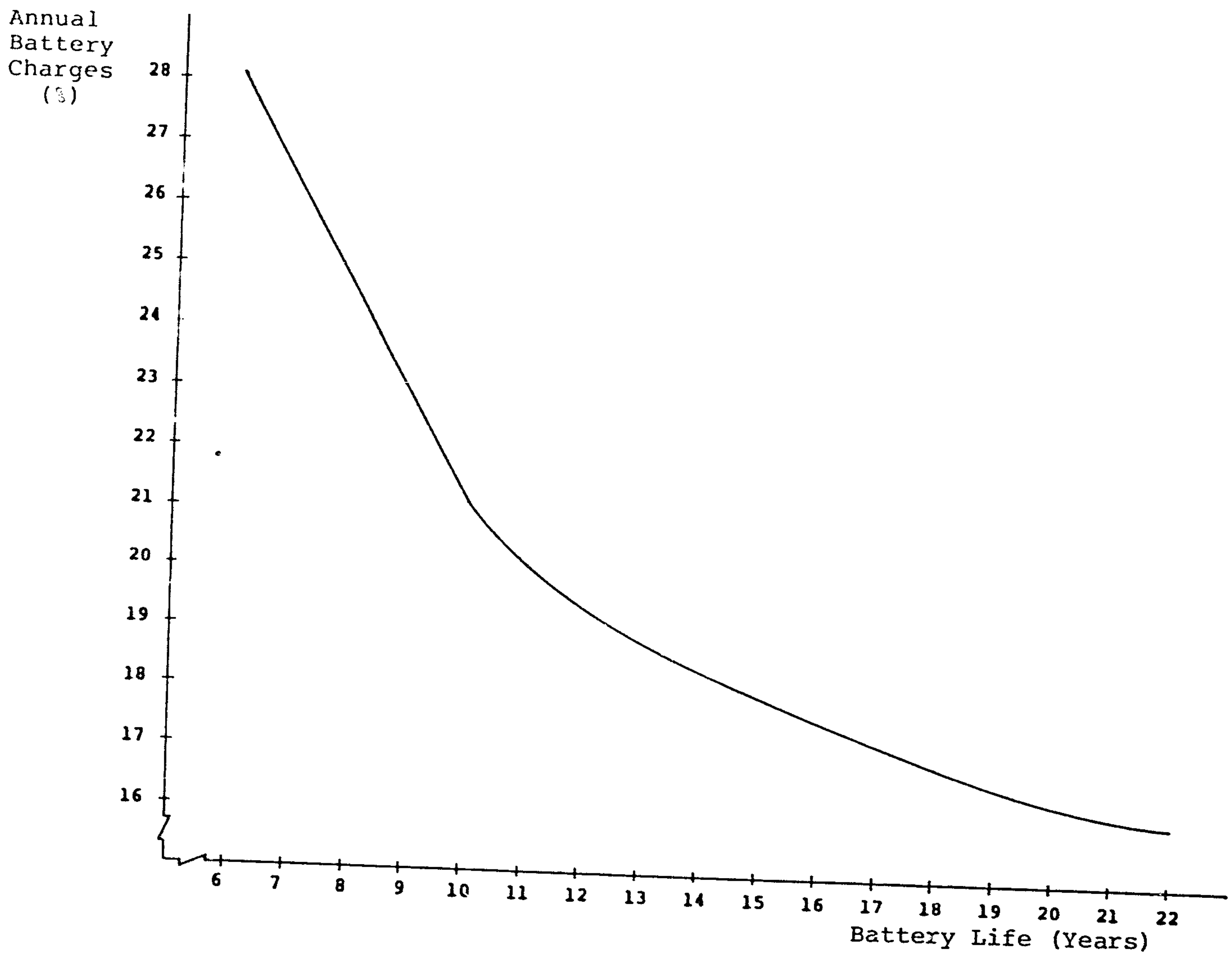


Figure ES-4. Effect of Battery Life on Battery Carrying Charges

Table ES-8

GENERATION CAPITAL COST ANALYSIS

	Pwafrr (1979 millions of dollars)
Replace Peaking Capacity	
Lead-Acid Battery Cost	(264)
Gas Turbine Savings	79
Net Capital Penalty	(185)
Replace Intermediate Capacity	
Lead-Acid Battery Cost	(264)
Oil Steam Savings	130
Net Capital Penalty	(134)

Table ES-9

PRODUCTION COST ANALYSIS

	Pwafrr (1979 million dollars)	
	Replace Peaking Capacity	Replace Intermediate Capacity
Operating Savings (Penalty)	16	(73)
Spinning Reserve Savings	58	58
Total Production Cost Savings (Penalty)	74	(15)

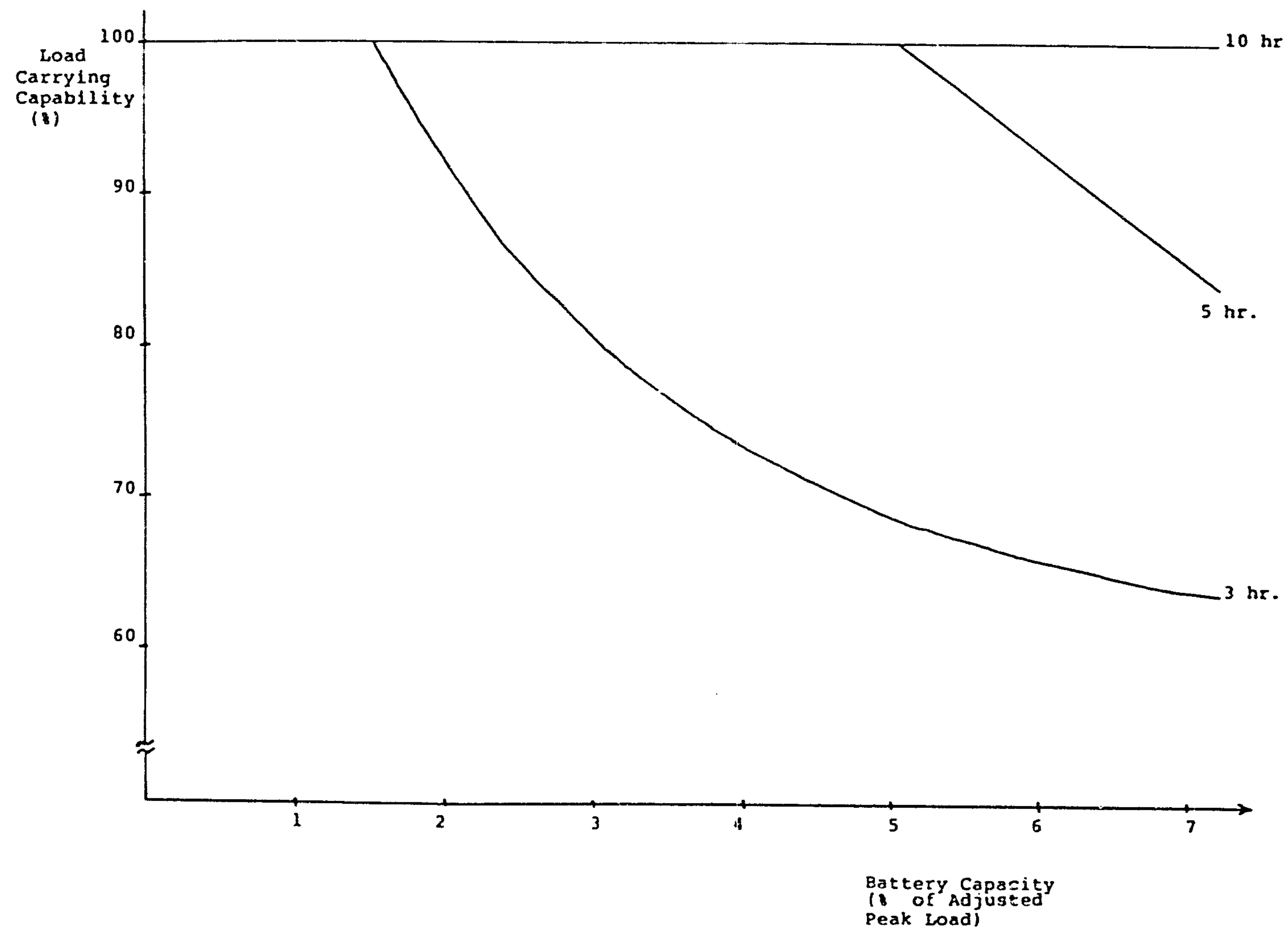


Figure ES-5. System Reliability - Installed Reserve Requirements
Effect of Limited Energy

Table ES-10

SUMMARY OF LEAD-ACID BATTERY COSTS AND SAVINGS

	Pwafrr Cost (Saving) Millions of 1979 Dollars	Equivalent Battery Installed Cost ($/kW)
COST		
Battery Capital Cost	264	400
SAVING		
Transmission	(39)	(59)
Distribution	(2)	(3)
Production Cost and Spinning Reserve	(74)	(112)
Replacement Capacity	(79)*	(120)*
Total	(194)	(294)
NET COST	70	106

*Includes credits for capacity reserve requirement savings. There are no credits for short installation lead time when compared to gas turbines.

SUMMARY OF COSTS AND SAVINGS

Table ES-10 summarizes all of the costs and savings identified for lead-acid batteries. This table shows each component not only in terms of Pwafrr but also in equivalence of $/kW of installed cost. As can be seen, savings of $294/kW have been identified as compared with the estimated $400/kW cost.

SENSITIVITY ANALYSES

Several of the key parameters in the analysis have been varied to determine the most important elements affecting the overall economic results. Results of these sensitivity analyses indicate that a combination of parameter changes would be sufficient to justify lead-acid battery installations. The most important parameters, other than the cost of the batteries themselves, have been found to be:

1. The relative costs of fuel for base load generating units (coal and nuclear) as compared to fuel for peaking units (oil).

2. The relative mix of nuclear, coal, and oil units on the particular utility system, and

3. The magnitude of transmission projects which could be cancelled.

4. The inclusion of inflation in the economic analyses.

In addition, it was determined that a recognition that inflation may be here to stay increases the incentives to install batteries. The assumption of a 6% inflation rate combined with a coal-oil fuel price differential on the order of \$1.25/MBtu is sufficient to make lead-acid batteries a break-even proposition for the reference system.

It should be noted that the 10% cost of money used throughout this report inherently includes an inflation adjustment. Thus, 10% is a proper value to use for the sensitivity to the inclusion of inflation analysis. To be completely consistent, a cost of money on the order of 4-5% should have been used for all other analyses. This would have decreased the net penalty for lead-acid batteries which was shown in Table ES-10.